# PRO•GRES•SION:

NOUN. A MOVEMENT OR DEVELOPMENT TOWARD A DESTINATION OR A MORE ADVANCED STATE, ESP. GRADUALLY OR IN STAGES.

SEE ALSO;

# CELTIC'S 2011 Q1 REPORT

Q1 INTERIM REPORT FOR THE THREE MONTHS ENDED MARCH 31, 2011

# SINCE STARTING CELTIC EXPLORATION IN 2002, OUR VISION HAS BEEN TO APPLY SOUND FINANCIAL PRINCIPLES, ACQUIRE QUALITY ASSETS AND DELIVER SUPERIOR VALUE.

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# FINANCIAL AND OPERATIONAL HIGHLIGHTS

| *(CA$ thousands, unless otherwise indicated)* | Three months ended March 31, **2011** | 2010 | Change |
|---|---|---|---|
| **FINANCIAL** | | | |
| Revenue, before royalties and financial instruments | **53,652** | 63,809 | -16% |
| Funds from operations | **32,659** | 35,083 | -7% |
| Basic ($/share) | **0.36** | 0.39 | -8% |
| Diluted ($/share) | **0.34** | 0.39 | -13% |
| Profit | **672** | 26,110 | -97% |
| Basic ($/share) | **0.01** | 0.29 | -97% |
| Diluted ($/share) | **0.01** | 0.29 | -97% |
| Capital expenditures, net of dispositions and drilling credits | **69,253** | (5,994) | - |
| Total assets | **818,492** | 677,010 | 21% |
| Bank debt, net of working capital | **147,879** | 126,366 | 17% |
| Shareholders' equity | **520,536** | 403,931 | 29% |
| Weighted average common shares outstanding (thousands) | | | |
| Basic | **91,444** | 89,360 | 2% |
| Diluted | **94,707** | 91,113 | 4% |
| **OPERATIONS** | | | |
| Production | | | |
| Oil (bbls/d) | **3,791** | 4,297 | -12% |
| Gas (mcf/d) | **70,884** | 78,031 | -9% |
| Combined (BOE/d) | **15,605** | 17,302 | -10% |
| Production per million shares (BOE/d) | **171** | 194 | -12% |
| Realized sales prices, after financial instruments | | | |
| Oil ($/bbl) | **76.96** | 70.65 | 9% |
| Gas ($/mcf) | **4.22** | 5.19 | -19% |
| Operating netbacks ($/BOE) | | | |
| Oil and gas revenue | **38.20** | 40.98 | -7% |
| Realized loss on financial instruments | **(0.33)** | (0.05) | |
| Realized sales price, after financial instruments | **37.87** | 40.93 | -7% |
| Royalties | **(4.77)** | (6.32) | -25% |
| Production expense | **(7.20)** | (9.25) | -22% |
| Transportation expense | **(0.44)** | (0.68) | -35% |
| Operating netback | **25.46** | 24.68 | 3% |
| Drilling activity | | | |
| Total wells | **22** | 21 | 5% |
| Working interest wells | **14.6** | 15.2 | -4% |
| Success rate on working interest wells | **100%** | 87% | 15% |
| Undeveloped land | | | |
| Gross acres | **689,856** | 312,217 | 121% |
| Net acres | **626,173** | 256,689 | 144% |

# MESSAGE TO SHAREHOLDERS

**Celtic Exploration Ltd. ("Celtic" or the "Company") is pleased to report to shareholders the Company's activities in the first quarter of 2011. During the quarter, Celtic drilled 22 (14.6 net) wells with an overall success rate of 100%. Production during the quarter averaged 15,605 BOE per day, a decrease of 10% from 17,302 BOE per day in the first quarter of 2010. During the quarter, the Company experienced significant downtime as a result of gas plant outages at the KA and K3 Gas Plants, where over 85% of the Company's production is processed, which negatively affected production for the quarter. The most significant downtime for production during the first quarter was the outage at the K3 Gas Plant, which was down from March 10 to April 8, 2011.**

In the first quarter of 2011, Celtic recorded funds from operations of $32.7 million ($0.34 per share, diluted), down from $35.1 million ($0.39 per share, diluted) reported in the same quarter of the previous year. Net capital expenditures during the quarter were $69.3 million and bank debt, net of working capital, at March 31, 2011 was $147.9 million, up 17% from $126.4 million at March 31, 2010.

## OPERATIONS UPDATE

The first quarter of 2011 proved to be Celtic's most active quarter since the Company started in 2002. In total, 19 operations were conducted during the quarter, with 12 of the operations occurring in Celtic's exciting new resource plays.

At Kaybob, Alberta, two Bluesky horizontals (1.0 net), one Notikewin horizontal (0.25 net) and four Montney horizontals (3.36 net) were drilled. With the colder weather in April, these wells were all completed prior to break-up.

In the Kaybob Duvernay shale play, four operations were conducted with three verticals (2.01 net) and one horizontal (0.33 net) being drilled. The horizontal well tested gas at 5.2 MMCF per day, with associated liquids estimated at 75 barrels per MMCF or 390 barrels per day. On a combined basis, after adjusting for shrinkage, the well's test equates to approximately 1,170 BOE per day. The vertical wells earned the Company additional lands in the play and provided valuable information regarding rock characteristics and liquids content. Two additional vertical tests are planned in 2011 that are expected to be equipped with seven-inch intermediate casing, set above the Duvernay zone, allowing the Company to drill these wells horizontally in the near future. Other industry participants are expected to become active in the area throughout the remainder of the year, further de-risking the play.

At Fir, Alberta, a two mile horizontal well was drilled and completed. The well tested at a gas rate of 13.1 MMCF per day, with associated liquids of 50 barrels per MMCF or 655 barrels per day. On a combined basis, after adjusting for shrinkage, the well's test equates to approximately 2,620 BOE per day. Celtic tied-in its two wells at Fir in late April and continues to develop the pool. The Company plans to drill a total of nine horizontals in 2011, the majority of which will be longer horizontals that will drain over the length of two sections of land.

At Inga, in north-east British Columbia, the Company continues to participate in the exploitation of a liquids-rich Doig play which is being developed through horizontal drilling. The Company's working interest in this play is 40%. During the first quarter, the Company participated in the drilling and completion of a horizontal well which tested gas at a rate of 4.0 MMCF per day and 1,400 barrels per day of flowing condensate. On a combined basis, after adjusting for shrinkage, the well's test equates to approximately 2,000 BOE per day. The well is currently tied-in and it is expected that horizontals drilled in the pool will eventually gravitate back to liquids yields that are similar to producing vertical wells in the range of 50 to 100 barrels per MMCF. Three additional wells are planned for the remainder of 2011.

# DE-RISKING THE COMPANY'S RESOURCE PLAYS AT RESTHAVEN IN THE MONTNEY AND AT KAYBOB IN THE DUVERNAY HAS COMMENCED WITH ENCOURAGING RESULTS.

At Resthaven, Alberta, Celtic carried out six operations which further delineate this exciting Montney play. Two vertical wells were deepened and tested at rates of 400 and 700 MCF per day. A third vertical was re-entered and deepened. This well was completed but not flow tested due to the onset of break-up. This well is expected to be tested in June.

In addition, three horizontals at Resthaven, were drilled during the quarter. The well located at 14-04-061-02W6 (100% WI) tested a lower interval below the middle Montney which turned out to be a lower permeability zone that proved to be difficult to frac. The Company was only able to complete five fracs successfully, resulting in a gas test rate of 2.4 MMCF per day. Celtic expects to drill a second horizontal leg in this well targeting the upper middle Montney formation, which appears to be a superior reservoir. The Company participated in the drilling and completion of a horizontal well located at 16-27-061-02W6 (30% WI); however, a test was not completed due to break-up. In addition, a horizontal well located at 15-31-060-02W6 was drilled and a completion is planned for the second quarter.

Celtic expects to drill 16.3 net wells in the Resthaven area during 2011. The Company has completed a portion of its 12-inch gas gathering system with the remainder to be built along with the compression facility in June and July.

**NON-CORE PROPERTY DISPOSITIONS**

During the first quarter, the Company completed the disposition of several non-core properties with production of approximately 235 BOE per day for proceeds of $17.2 million, prior to adjustments. The Company expects to continue to monetize non-core assets and has identified potential assets that could be divested representing approximately 1,100 BOE per day of production.

**OUTLOOK**

In spite of low natural gas prices, Celtic is able to generate profitable returns on its investments due to the nature of its asset base that is primarily made up of predictable and repeatable resource type development in liquids-rich natural gas formations. Celtic expects to exit 2011 with production of approximately 24,500 BOE per day. The Company is excited about its active exploration program and looks forward to updating shareholders with further results in the near future.

# MANAGEMENT'S DISCUSSION & ANALYSIS

## INTRODUCTION

**The Company was incorporated on April 16, 2002. Celtic's head office is based in Calgary, Alberta, Canada. Common shares of the Company are listed and posted for trading on the Toronto Stock Exchange ("TSX") under the symbol "CLT".**

The following management's discussion and analysis ("MD&A") is dated June 6, 2011 and should be read in conjunction with the Company's unaudited interim financial statements and related notes for the period ended March 31, 2011. The accompanying financial statements of Celtic have been prepared by management and approved by the Company's Audit Committee and Board of Directors. These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), specifically IFRS 1, "First-time Adoption of International Financial Reporting Standards", and with International Accounting Standard 34, "Interim Financial Reporting". Previously, the Company prepared its financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). In accordance with IFRS 1, Celtic's transition date to IFRS was January 1, 2010 and, therefore, the comparative information for 2010 has been prepared in accordance with the Company's IFRS accounting policies.

Additional information relating to Celtic can be found on the SEDAR website at www.sedar.com.

### FORWARD-LOOKING STATEMENTS

This document contains expectations, beliefs, plans, goals, objectives, assumptions, information and statements about future events, conditions, results of operations or performance that constitute "forward-looking information" or "forward-looking statements" (collectively, "forward-looking statements") under applicable securities laws. Undue reliance should not be placed on forward-looking statements. Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements. We caution that the foregoing list of risks and uncertainties is not exhaustive. Events or circumstances could cause actual dates to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements. The forward-looking statements contained in this press release are made as of the date hereof and the Company does not intend, and does not assume any obligation, to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise unless expressly required by applicable securities laws.

The information set out herein with respect to forecasted 2011 results is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Celtic's reasonable expectations as to the anticipated results of its proposed business activities for 2011. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

### NON-IFRS FINANCIAL MEASUREMENTS

This document contains the terms "funds from operations", "operating netback" and "production per share" which do not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other companies. Funds from operations and operating netbacks are used by Celtic as key measures of performance. Funds from operations and operating netbacks are not intended to represent operating profits nor should they be viewed as an alternative to cash provided by operating activities, profit or other measures of financial performance calculated in accordance with IFRS. Operating netbacks are determined by deducting royalties, production expenses and transportation expenses from oil and gas revenue. Funds from operations are determined by adding back change in non-cash operating working capital to cash provided by operating activities. The Company calculates funds from operations per share using the same method and shares outstanding which are used in the determination of profit per share.

The following table reconciles cash provided by operating activities to funds from operations:

| *($ thousands)* | Three months ended March 31, 2011 | Three months ended March 31, 2010 |
|---|---|---|
| Cash provided by operating activities | 27,237 | 44,901 |
| Change in non-cash operating working capital | 5,422 | (9,818) |
| Funds from operations | 32,659 | 35,083 |

## OTHER MEASUREMENTS

All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Where amounts are expressed on a barrel of oil equivalent ("BOE") basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel and sulphur volumes have been converted to oil equivalence at 0.6 long tons per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to oil in this discussion include crude oil and natural gas liquids ("NGLs"). NGLs include condensate, propane, butane and ethane. References to gas in this discussion include natural gas and sulphur.

## CRITICAL ACCOUNTING ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of IFRS that have a significant impact on the financial results of the Company. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. The following discussion highlights the significant changes in the Company's critical accounting estimates from those disclosed in the MD&A for the year ended December 31, 2010, as a result of the adoption of IFRS.

### Opening Balance Sheet – Full Cost Pool

On transition to IFRS, the Company's property, plant and equipment ("PP&E") assets accumulated in a country cost centre and were allocated pro-rata based on proved reserve values to major areas, which consolidate into cash generating units ("CGUs"). The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as geo-scientific interpretation, production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction, nor do they represent costs historically spent.

### Exploration and Evaluation Assets

The determination of technical feasibility and commercial viability, based on the presence of proved plus probable reserves, results in the transfer of assets from exploration and evaluation ("E&E" assets) to PP&E. As discussed above, the estimate of proved and probable reserves is inherently complex and requires significant judgement. Therefore, any material change to reserve estimates could affect the technical feasibility and commercial viability of the underlying assets.

### Asset Impairments

For purposes of impairment testing, PP&E is aggregated into CGUs based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. In addition, the testing of CGUs for impairment, as well as the assessment of potential impairment reversals, requires an estimate of the recoverable amount. The estimate of the recoverable amount requires a number of assumptions and estimates including geo-scientific interpretation, production forecasts,

commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

**Decommissioning Liabilities**

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. The total decommissioning liability was estimated by management based on the Company's net ownership in wells and facilities. This includes all estimated costs to abandon, reclaim or decommission wells and facilities and the estimated timing of the costs to be incurred in future periods. Estimates of these costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. The liability, the related asset and the expense are impacted by estimates with respect to the cost and timing of decommissioning. The discount rate used to estimate decommissioning liabilities is updated each reporting period under IFRS, changes in the risk free rate can change the amount of the liability, and these changes could potentially be material in the future.

**Share-Based Compensation**

Compensation costs recorded pursuant to share-based compensation plans are subject to estimated fair values and forfeiture rates.

**Derivative Financial Instruments**

The estimated fair value of derivative financial contracts resulting in derivative financial assets and liabilities, by their very nature, is subject to measurement uncertainty.

**Deferred Taxes**

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax liabilities recognize to the extent that temporary differences will be payable in future periods. The calculation of the liability involves a significant amount of estimation including an evaluation of when the temporary differences will reverse; an analysis of the amount of future taxable earnings; and the availability of cash flows and the application of tax laws. Significant changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

## ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

The three month period ending March 31, 2011 is the first interim period for which the Company has applied IFRS. In accordance with IFRS 1, the Company's transition date to IFRS was January 1, 2010 and, therefore, the comparative information for 2010 has been prepared in accordance with IFRS. The Company concluded that the adoption of IFRS did not have a significant impact on any of its internal control processes. In terms of financial literacy, the Company recently hired new staff and continues to provide training in order to ensure that there is a strong level of knowledge of IFRS throughout the organization. The information below summarizes the significant accounting policies that the Company has adopted under IFRS as well as the actual impact of adopting the policies.

## ACCOUNTING POLICIES

The Company's financial statements for the year ending December 31, 2011 must use the IFRS standards that are in effect at December 31, 2011 and, therefore, the unaudited financial statements for the three months ending March 31, 2011 have been prepared using the standards that are expected to be effective at the end of 2011. However, the Company's IFRS accounting policies will only be finalized when the first annual IFRS financial statements are prepared for the year ending December 31, 2011. Therefore, certain accounting policies that the Company currently expects to follow under IFRS may not be adopted and the application of such policies to certain transactions or circumstances may be modified. As a result, the unaudited financial statements for the three months ended March 31, 2011 may be subject to change.

The Company's unaudited financial statements for the three months ended March 31, 2011 provide the following reconciliations from previous GAAP to IFRS:

- Statements of financial position as at January 1, 2010, March 31, 2010 and December 31, 2010; and
- Statements of profit and comprehensive income for the three months ended March 31, 2010, and the year ended December 31, 2010.

A summary of the significant accounting policies that the Company has adopted in the transition from previous GAAP to IFRS, including the significant elections and exemptions that are allowed upon first time adoption of IFRS, as well as the significant impacts on these financial statements, have been provided below. Note that the IFRS balances provided below are not audited.

**Property, Plant and Equipment**

Under previous GAAP, Celtic accounted for its oil and gas properties in a country cost centre using full-cost accounting. IFRS 1 provides the option for entities using full-cost accounting for oil and gas activities under previous GAAP to elect to measure oil and gas assets at the transition date at the historical net book value or at fair value, rather than applying IFRS rules retrospectively. The Company elected to measure its oil and gas assets at the net book value determined under previous GAAP, resulting in undeveloped land of $39.0 million being reclassified to exploration and evaluation assets on the transition date. The remaining development and production assets that were accumulated in a country cost centre under previous GAAP could be allocated to the cost centre's underlying assets pro-rata using reserve volumes or values. The Company elected to allocate these assets using reserve values.

Under IFRS, development and production assets are depleted at the major area level using the unit-of-production method based on the estimated proved reserves before royalties, whereas, under previous GAAP these assets were accumulated in a country cost centre and depleted using the unit-of-production method based on the estimated proved reserves before royalties. As a result of depleting at the major area level based on proved reserves before royalties, depletion, depreciation and accretion ("DD&A") increased $1.2 million for the three months ended March 31, 2010, with a corresponding increase to PP&E.

The carrying amounts of PP&E are grouped into CGUs and reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount exceeds the recoverable amount, the CGU is written down with an impairment recognized in net earnings. Assets are grouped into CGUs based on separately identifiable and largely independent cash inflows. Estimates of future cash flows used in the calculation of the recoverable amount are based on reserve evaluation reports prepared by independent petroleum reservoir engineers. The recoverable amount is the higher of fair value less cost to sell and the value-in-use. Fair value less cost to sell is derived by estimating the discounted after-tax future net cash flows. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of reserves and discounted using market based rates. Value-in-use is assessed using the present value of the expected future cash flows.

Impairments of PP&E are reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been had no impairment been recognized. The impairment test of PP&E was performed at January 1, 2010 in accordance with IFRS and impairment in the amount of $2.4 million was recorded. At December 31, 2010 and March 31, 2011, there were no indicators of impairment; therefore an impairment test of PP&E was not required.

**Exploration and Evaluation Assets**

Exploration and evaluation assets are comprised of the accumulated expenditures incurred in an area where technical feasibility and commercial viability has not yet been determined. Exploration and evaluation assets include undeveloped land. At January 1, 2010 and December 31, 2010, E&E assets of $39.0 million and $67.8 million, respectively, were recognized, whereas these amounts were included in PP&E under previous GAAP.

Technical feasibility and commercial viability are considered to be determinable when reserves are discovered. Upon determination of reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to PP&E. The Company's policy under IFRS is to impair E&E assets on land expiries using a modified successful efforts method of accounting. Accordingly, $0.3 million and $2.3 million was recognized through expiries for the three months and year ended March 31, 2010 and December 31, 2010, respectively, with a corresponding decrease to E&E assets.

E&E assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability; and (ii) indicators suggest that the carrying amount exceeds the recoverable amount. E&E assets are tested for impairment at the operating segment level by combining E&E assets with PP&E. The recoverable amount includes discounted after tax future net cash flows as described in the PP&E impairment test, plus the fair market values of undeveloped land and seismic. Impairments of E&E assets are reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been had no impairment been recognized. The impairment test of E&E was performed at January 1, 2010 in accordance with IFRS and no impairments existed. At December 31, 2010 and March 31, 2011, there were no indicators of impairment; therefore an impairment test of E&E was not required.

### Decommissioning Obligations

The Company recognizes the present value of a decommissioning obligation in the period in which it is incurred. The obligation is recorded as a liability on a discounted basis using the relevant risk free rate, with a corresponding increase to the carrying amount of the related asset. Under previous GAAP, a credit-adjusted risk free discount rate was used to estimate the Company's decommissioning obligations. For entities taking the full-cost oil and gas accounting exemption discussed above, IFRS 1 requires that any difference in the decommissioning obligations calculated between IFRS and previous GAAP be recognized directly in retained earnings; accordingly, on transition, the Company's decommissioning obligations increased by $14.6 million, deferred income tax liability decreased by $3.6 million and retained earnings decreased by $10.9 million. At December 31, 2010, the Company's decommissioning obligations was $15.8 million higher under IFRS than under previous GAAP.

### Share-Based Compensation

In accordance with IFRS 2 Share-based Payment, as at the transition date, the Company revalued its contributed surplus arising from share-based compensation to recognize estimated forfeiture rates. Under previous GAAP, stock options granted were amortized over the vesting period of three years. Under IFRS, graded vesting is being used which results in increased share-based compensation expense during the earlier part of the three year vesting period instead of equally over the three years.

## CHANGES IN ACCOUNTING POLICIES

A summary of changes in accounting policies used by Celtic can be found in Note 2 of the Company's March 31, 2011 unaudited interim financial statements.

## DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 of the Canadian Securities Administrators, to provide reasonable assurance that: (i) material information relating to the Company is made known to the CEO and the CFO by others, particularly during the period in which the interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

## INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and the CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The Company is required to disclose any change in the Company's internal controls over financial reporting that occurred during the period from January 1, 2011 to March 31, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes were identified during this period.

Due to its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation relating to the effectiveness in future periods are subject to the risk that controls may become inadequate as a result of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

## GROWTH STRATEGY

The Company implements a full cycle exploration and development program and, at the same time, opportunistically seeks to acquire assets with exploitation potential. This strategy has proved successful to date as is evidenced by Celtic's rapid growth since commencing active oil and gas operations in September 2002. To complement this strategy, the Company has assembled and retained a team of experienced and qualified personnel and is well positioned financially to act quickly on new opportunities.

## RESULTS OF OPERATIONS

### FIRST QUARTER 2011 HIGHLIGHTS

- Drilled 22 (14.6 net working interest) wells during the quarter resulting in an overall success rate of 100%;
- Recorded average daily production of 15,605 BOE per day, down from 17,302 BOE per day in the first quarter of 2010;
- Received an average price of $37.87 ($38.20 before hedging) per BOE, down 7% from $40.93 ($40.98 before hedging) per BOE in the first quarter of 2010 and recorded an operating netback of $25.48 per BOE, up 3% from $24.68 per BOE in the corresponding quarter of 2010;
- Generated $32.7 million in funds from operations for the three month period ended March 31, 2011, down 7% from $35.1 million in the same quarter of the previous year. Reported funds from operations per share, diluted, of $0.34, a decrease of 12% from $0.39 per share in the first quarter of the previous year; and
- Completed an equity financing by way of a short form prospectus on a bought deal basis by issuing 5.0 million common shares at a price of $20.30 per share, resulting in gross proceeds of $101.5 million.

### PRODUCTION

Oil and gas production in the first quarter of 2011 decreased 10% to average 15,605 BOE per day compared to 17,302 BOE per day in the same quarter of 2010. Production per million shares outstanding for the three months ended March 31, 2011 averaged 171 BOE per day, down 12% from 194 BOE per day in the corresponding quarter of the previous year. Lower production volumes in 2011 were the result of certain non-core property dispositions and significant plant downtime resulting from outages at the KA and K3 Gas plants, where the majority of the Company's production is processed.

## REVENUE

Revenue, before royalties, and before gains or losses on financial instruments, for the three months ended March 31, 2011, was $53.7 million, a decrease of 16% compared to $63.8 million in the same quarter of the previous year. Decrease in revenue for 2011 was due to lower production volumes and lower realized gas prices.

The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial instruments for the three months ended March 31, 2011 was $37.87 per BOE, a decrease of 7% compared to the corresponding three month period of the previous year.

## OIL OPERATIONS

Oil production for the first quarter ended March 31, 2011 averaged 3,791 barrels per day, a decrease of 12% compared to 4,297 barrels per day in the same quarter of the previous year.

The average price received for oil sales, after realized financial instruments, for the first quarter ended March 31, 2011 was $76.96 ($78.30 before financial instruments) per barrel, up 9% from the average price of $70.65 ($70.65 before financial instruments) per barrel received in the first quarter of 2010. During the three month period ended March 31, 2011, the average WTI crude oil index price was US$94.10 per barrel, up 19% from US$78.72 per barrel in the same period of 2010. During the three month period ended March 31, 2011, the average differential between the Canadian dollar equivalent WTI price and the Company's realized wellhead oil price, before financial instruments, was 15.7% compared to 13.9% in the same period of 2010.

For the quarter ended March 31, 2011, average oil royalties were 18.7% of revenue, after realized financial instruments (18.4% of revenue, before financial instruments). In the first quarter of the previous year, average oil royalties were 20.9% of revenue, after financial instruments (20.9% of revenue, before financial instruments). Lower oil royalty rates in 2011, before financial instruments, reflect the benefit of the royalty incentive programs offered by the Alberta government that Celtic is able to take advantage of.

Transportation expenses for oil production in the first quarter of 2011 averaged $0.14 per barrel compared to $0.30 per barrel in the first quarter of 2010. Lower per unit transportation expenses in 2011 reflect the larger portion of newer NGL production from Kaybob which is mostly pipeline connected and therefore less expensive to transport compared to trucking oil.

For the first quarter ended March 31, 2011, oil production expenses were $7.60 per barrel. In the same quarter of the previous year, oil production expenses were $12.56 per barrel. Lower per unit production expenses in 2011 reflect the larger portion of newer NGL production from Kaybob which is less expensive to produce compared to the Company's older oil production.

## GAS OPERATIONS

Gas production for the first quarter ended March 31, 2011 averaged 70,884 MCF per day, a decrease of 9% compared to 78,031 MCF per day in the corresponding quarter of the previous year. Decreases in gas production in 2011 were primarily a result of non-core property dispositions and plant downtime resulting from outages at the KA and K3 Gas Plants.

The average price received for gas sales, after realized financial instruments, for the first quarter ended March 31, 2011 was $4.22 ($4.22 before financial instruments) per MCF, down 19% from the average price of $5.19 ($5.20 before financial instruments) per MCF received in the first quarter of 2010. During the three month period ended March 31, 2011, the average AECO-C natural gas index price was $3.56 per GJ ($3.75 per MMBTU), down 24% from $4.69 per GJ ($4.95 per MMBTU) in the same period of 2010. During the three month period ended March 31, 2011, the average differential between the AECO-C price and the Company's realized wellhead gas price, before financial instruments, was 12.5% compared to 5.1% in the same period of 2010.

For the quarter ended March 31, 2011, average gas royalties were 6.6% of revenue, after financial instruments (6.6% of revenue, before financial instruments). In the first quarter of the previous year, average gas royalties were 11.4% of revenue, after financial instruments (11.4% of sales, before financial instruments). Lower gas royalty rates in 2011, before financial instruments, are a result of the benefits of longer depth horizontal wells which receive favourable treatment under the Alberta royalty framework and new production qualifying for various incentive programs. In addition, royalties are reduced further as the Company continues to receive gas cost allowance credits which do not fluctuate with gas prices.

Transportation expenses for the first quarter ended March 31, 2011 were $0.09 per MCF, down from $0.13 per MCF for the same quarter in the previous year.

For the first quarter ended March 31, 2011, production expenses of $1.18 per MCF were 13% lower than $1.36 per MCF in the corresponding quarter of the previous year. Production expenses in 2011 are lower as the Company continues to divest of its higher production cost properties and adds new production in its lower production cost properties.

**OTHER EXPENSES**

For the quarter ended March 31, 2011, interest expense was $1.6 million; general and administrative ("G&A") expenses were $1.3 million ($0.93 per BOE); and share based compensation expense was $1.2 million. Depletion, depreciation and amortization ("DD&A") expenses were $32.1 million ($22.83 per BOE), accretion on decommissioning obligations was $0.2 million and asset expiries was $1.7 million.

In the previous year, for the quarter ended March 31, 2010, interest expense was $1.3 million; G&A expenses were $1.4 million ($0.89 per BOE); and share based compensation expense was $0.7 million. DD&A expenses were $28.3 million ($18.00 per BOE), accretion on decommissioning obligations was $0.2 million and impairment of assets was $0.3 million.

The increase in interest expense in 2011 reflects higher average bank debt levels. Higher DD&A expense per BOE reflects the addition of proved reserves at higher than historic average costs. Impairment of asset charges relate to a dry shallow gas property located in southern Alberta.

**TAXES**

For the quarter ended March 31, 2011, Celtic provided for a provision of deferred income taxes in the amount of $0.7 million, compared to a provision of $9.7 million in the first quarter of 2010.

For the three month period ended March 31, 2011, Celtic is not required to pay current income taxes as it has sufficient income tax deductions available to shelter taxable income for the period. Estimated income tax deductions available at March 31, 2011 are $498.9 million.

**PROFIT**

Profit for the first quarter ended March 31, 2011 was $0.7 million ($0.01 per share basic and diluted) compared to profit of $26.1 million ($0.29 per share basic and diluted) in the first quarter of 2010. On a barrel of oil equivalent basis, profit in the first quarter of 2011 was $0.47 per BOE, compared to profit of $16.77 per BOE in the first quarter of 2010.

During the first quarter of 2011, funds from operations were $32.7 million ($0.36 per share basic and $0.34 per share diluted). On a barrel of oil equivalent basis, funds from operations in the first quarter of 2011 were $23.27 per BOE, up 3% from $22.53 per BOE in the same quarter of 2010.

Lower earnings and funds from operations in 2011 reflect the decrease in production compared to 2010 and the lower realized price per BOE combined oil and gas price received in 2011, which were partially offset by lower per unit expenses. In addition, earnings in 2010 were higher due to a gain on sale of assets in the amount of $29.6 million, compared to a gain in 2011 of $9.7 million.

### CAPITAL EXPENDITURES

During the quarter ended March 31, 2011, Celtic spent $87.6 million on capital projects. Drilling and completion operations accounted for $64.7 million, equipment and facility expenditures were $20.7 million and $2.2 million was spent on land and seismic. Net capital expenditures, after drilling royalty credits, acquisitions and dispositions were $71.5 million, up from negative $6.0 million in the first quarter of 2010, where proceeds from dispositions exceeded expenditures.

At March 31, 2011, the Company had 689,856 gross (626,173 net) acres of undeveloped land. The Company continues to acquire land and build on its inventory of prospects for future drilling.

### DRILLING ACTIVITY

During the first quarter of 2011, the Company drilled 22 (14.6 net) natural gas wells, for an overall success rate of 100%. During the first quarter of 2010, Celtic drilled 21 (15.2 net) wells, with an overall success rate of 87%. The average measured depth of net wells drilled in the first quarter of 2011 was 3,615 metres, an increase of 3% compared to the average drilling measured depth of 3,504 metres in the first quarter of 2010.

## CAPITAL RESOURCES AND LIQUIDITY

### SOURCE OF FUNDS

Investment funding for capital expenditures incurred in the first three months of 2011 was provided by proceeds from property dispositions, proceeds from the issue of common shares and by cash provided by operating activities.

The Company has a syndicated bank credit facility in the amount of $215.0 million. At March 31, 2011, Celtic had drawn $100.0 million or 47% of its authorized borrowing amount, leaving sufficient unused credit lines available to fund on-going capital expenditures and working capital deficiencies. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. The credit facility matures on June 28, 2011 and may be extended for an additional 364 days.

Celtic expects to fund future capital expenditures through the use of a combination of cash provided by operating activities and bank debt, supplemented by new equity share offerings, as required.

### WORKING CAPITAL

The capital intensive nature of Celtic's activities may create a working capital deficiency position during periods with high levels of capital investment. However, during such periods, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At March 31, 2011, the working capital amount plus outstanding bank debt represented 69% of the Company's maximum authorized bank borrowing credit limit.

### LIQUIDITY

Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company's financial liabilities are comprised of accounts payable, accrued liabilities and bank debt.

During 2009 and 2010, many oil and gas companies faced a number of challenges resulting from weakening commodity prices and tight credit markets. After falling into a recession, the global economy has commenced a recovery leading to an increase in demand

for commodities and better access to capital. Celtic has good relationships with its syndicate of lenders. The Company's existing credit facility matures on June 28, 2011 and may be extended for an additional 364 days. In addition, Celtic successfully closed a $101.5 million equity financing at the end of the first quarter of 2011.

The Company manages liquidity risk through the prudent use of debt, interest rate, currency and commodity price risk management and through an actively managed production and capital expenditure budget process.

### SHARE INFORMATION

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. The Company's shareholders approved a two-for-one stock split effective May 6, 2010. All references to common shares and stock options in these financial statements are on a post stock split basis. As at March 31, 2011, there were 96.4 million common shares outstanding (as at June 6, 2011, there were 97.2 million common shares outstanding). There are no preferred shares outstanding.

As at March 31, 2011, directors, employees and certain consultants have been granted options to purchase 6.0 million common shares of the Company at an average exercise price of $8.48 per share.

The Company's common shares trade on the TSX under the symbol "CLT".

### FUTURE COMMITMENTS – FINANCIAL INSTRUMENTS

The Company may, from time to time, enter into fixed price contracts and derivative financial instruments with respect to oil and gas sales, currency exchange and interest rates in order to secure a certain amount of cash flow to protect a desired level of capital spending.

The following is a summary of future oil sales swap contracts in effect as at March 31, 2011, that have fixed future sales prices based on the NYMEX WTI crude oil index, converted to Canadian dollars:

| Daily Quantity | Remaining term of contract | Fixed price per barrel (bbl) |
|---|---|---|
| 1,000 bbls/d | April 1 to December 31, 2011 | $ 90.00 |
| 1,000 bbls/d | April 1 to December 31, 2011 | $ 91.80 |

The following is a summary of interest rate swap contracts that settle based on the floating Canadian Dollar Banker Acceptance CDOR rate, in effect as at March 31, 2011:

| Amount | Remaining term of contract | Fixed interest rate per annum |
|---|---|---|
| CA$100,000,000 | April 1 to April 21, 2011 | 2.07% |

### CONTRACTUAL OBLIGATIONS

Celtic has a committed term credit facility with certain financial institutions. The authorized borrowing amount under this facility as at March 31, 2011 was $215.0 million, of which $100.0 million was outstanding. Interest under this facility is payable monthly. Additional disclosure relating to bank debt is provided in the notes to the financial statements.

From time to time, the Company enters into agreements to transport and market oil and gas production. In addition, the Company has entered into agreements with third parties that provides employees with access to specialized computer software and information including production and reserves data, geological data, accounting systems and land management systems. As a normal course of business, the Company leases office space, vehicles for field personnel and office equipment such as computers, printers and photocopiers.

The Company is committed to future payments under the following agreements:

| CONTRACTUAL OBLIGATIONS<br>*($ thousands)* | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|
| Operating lease – office building | $ 267 | $ 530 | $ 530 | $ 530 | $ 530 | $ 221 | $ 2,608 |
| Operating lease – vehicles | 141 | 93 | 50 | 4 | – | – | 288 |
| Firm transportation agreements | 14 | – | – | – | – | – | 14 |
| Total | $ 422 | $ 623 | $ 580 | $ 534 | $ 530 | $ 221 | $ 2,910 |

Office building operating lease relates to rental office space in Calgary, Alberta which expires on May 31, 2016.

### RELATED PARTY AND OFF-BALANCE SHEET TRANSACTIONS

The Company has retained the law firm of Borden Ladner Gervais LLP ("BLG") to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic is a partner of this law firm. During the first three months of 2011, the Company incurred $0.1 million in costs with BLG. These amounts have been recorded at the exchange amount. The Company expects to continue using the services of this law firm from time to time.

Celtic was not involved in any off-balance sheet transactions in the periods ended March 31, 2010 and 2011.

## SUPPLEMENTAL QUARTERLY INFORMATION

The Company has been successful in providing strong growth in funds from operations and daily average production through its drilling activities. The following tables summarize key financial and operating information by quarter for the past eight quarters (amounts for 2010 and 2011 were determined using IFRS and amounts for 2009 were determined using previous GAAP):

| *($ thousands, except per unit amounts)* | **2011 Q1** | 2010 Q4 | 2010 Q3 | 2010 Q2 | **2010 Q1** | 2009 Q4 | 2009 Q3 | 2009 Q2 |
|---|---|---|---|---|---|---|---|---|
| Gross oil & gas revenue *($)* | **53,652** | 53,041 | 47,989 | 57,202 | **63,809** | 60,146 | 40,365 | 30,668 |
| Funds from operations *($)* | **32,659** | 30,625 | 30,963 | 34,122 | **35,083** | 42,003 | 27,874 | 20,008 |
| Per share – basic *($/share)* | **0.36** | 0.34 | 0.34 | 0.38 | **0.39** | 0.47 | 0.32 | 0.23 |
| Per share – diluted *($/share)* | **0.34** | 0.33 | 0.34 | 0.37 | **0.39** | 0.46 | 0.31 | 0.23 |
| Profit (loss) *($)* | **672** | (1,284) | (1,898) | 3,237 | **26,110** | 906 | (13,667) | (5,459) |
| Per share – basic *($/share)* | **0.01** | (0.01) | (0.02) | 0.04 | **0.29** | 0.01 | (0.15) | (0.06) |
| Per share – diluted *($/share)* | **0.01** | (0.01) | (0.02) | 0.04 | **0.29** | 0.01 | (0.15) | (0.06) |
| Total assets *($)* | **818,492** | 750,346 | 710,764 | 678,587 | **677,010** | 678,770 | 657,919 | 663,531 |
| Bank debt, net of working capital *($)* | **147,879** | 203,381 | 168,734 | 128,322 | **126,366** | 168,417 | 159,319 | 145,976 |
| Production *(BOE/d)* | **15,605** | 17,385 | 16,506 | 18,029 | **17,302** | 17,274 | 15,307 | 10,909 |
| Production per million shares *(BOE/d)* | **171** | 192 | 183 | 201 | **194** | 194 | 173 | 125 |
| Sales price, after derivatives *($/BOE)* | **37.87** | 34.21 | 33.73 | 35.20 | **40.93** | 42.17 | 35.11 | 39.78 |
| Operating netback *($/BOE)* | **25.46** | 23.96 | 22.08 | 22.75 | **24.68** | 28.42 | 21.94 | 23.06 |
| Netback as a percentage of sales | **67%** | 70% | 65% | 65% | **60%** | 67% | 62% | 58% |

## BUSINESS RISKS

Celtic's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers, intermediate and senior producers, to the much larger integrated petroleum companies. Celtic is subject to a number of risks which are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, financial and liquidity risks and environmental and safety risks.

In order to reduce exploration risk, Celtic employs highly qualified and motivated professional employees who have demonstrated the ability to generate quality proprietary geological and geophysical prospects. To maximize drilling success, Celtic explores in areas that afford multi-zone prospect potential, targeting a range of shallower low to moderate risk prospects with some exposure to select deeper high-risk prospects with high-reward opportunities.

Celtic has retained an independent engineering consulting firm that assists the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, projected production, future production costs and government regulation. Such estimates may vary from actual results.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most advanced technology and information systems. In addition, Celtic strives to operate the majority of its prospects, thereby maintaining operational control. The Company does rely on its partners in jointly owned properties that Celtic does not operate.

Celtic is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate, which in turn respond to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Celtic may periodically use futures and options contracts to hedge its exposure against the potential adverse impact of commodity price volatility.

Exploration and production for oil and gas is very capital intensive. As a result, the Company relies on equity markets as a source of new capital. In addition, Celtic utilizes bank financing to support on-going capital investment. Funds from operations also provide Celtic with capital required to grow its business. Equity and debt capital is subject to market conditions and availability may increase or decrease from time to time. Funds from operations also fluctuate with changing commodity prices.

### SAFETY AND ENVIRONMENT

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. Celtic maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.

### CLIMATE CHANGE

The Federal Government has announced its intention to regulate greenhouse gases ("GHG") and other air pollutants. As these regulations are under development, the Company is unable to predict the total impact of the potential regulations upon its business. The Alberta Government has set targets for GHG emission reductions. In order to comply with the Alberta regulations, companies can make operating improvements to its facilities, purchase carbon offsets or make a monetary contribution to the Alberta Climate Change and Emissions Management Fund.

## BUSINESS OUTLOOK

### ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

Certain information with respect to Celtic contained herein, including management's assessment of future plans and operations, contains forward-looking statements. These forward-looking statements are based on assumptions and are subject to numerous risks and uncertainties, certain of which are beyond Celtic's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency exchange rate fluctuations, imprecision of reserve estimates, environmental risks, competition from other explorers, stock market volatility and ability to access sufficient capital. As a result, Celtic's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur. In addition, the reader is cautioned that historical results are not necessarily indicative of future performance.

### CURRENT ECONOMIC ENVIRONMENT

After the financial community around the world was rocked with unprecedented losses and business failures in 2009, the recovery that commenced in 2010 appears to be progressing, however, the current economic environment remains challenging and uncertain. Political upheaval in the Middle East remains a wild card and could hamper world economic recovery if oil supply is negatively affected. Inflation around the world could also have an impact on economic recovery which would ultimately affect the demand for energy in high growth countries such as India and China. Celtic expects to see a continued improving economic environment in 2011, with improving natural gas prices, stable oil prices, less volatile financial markets and good access to capital markets.

In this environment, Celtic has maintained financial flexibility through the prudent use of bank debt and through an active risk management strategy whereby a portion of cash flow for 2011 has been secured to a certain extent through the use of oil price financial instruments. In addition, the Company has accessed equity market early in the year adding financial strength to its balance sheet.

Celtic's capital expenditure program remains flexible and if the current economic environment deteriorates, the Company has the ability to defer expenditures into the future.

### 2011 GUIDANCE

Celtic continues to remain optimistic about its future prospects. Celtic is opportunity driven and is confident that it can continue to grow the Company's production base by building on its current inventory of development prospects and by adding new exploration prospects. Celtic will endeavour to maintain a high quality product stream that on a historical basis receives a superior price with reasonably low production costs. In addition, the Company takes advantage of royalty incentive programs in order to further increase netbacks. Celtic will continue to focus its exploration efforts in areas of multi-zone hydrocarbon potential.

Celtic's Board of Directors has approved the Company's 2011 capital expenditure budget of $260.0 million. The Company expects to spend $207.0 million on drilling and completing wells, $40.0 million on facilities, equipment and pipelines, and $13.0 million on land and seismic.

On May 16, 2011, the Company issued a press release outlining various production interruptions resulting from gas plant outages and repair and maintenance downtime. After taking into consideration these production interruptions, Celtic has changed its production and financial expectations as outlined below.

Celtic expects production in 2011 to average between 19,300 and 19,700 BOE per day (previously between 20,000 and 20,400 BOE per day). This estimate is based on production in the second quarter averaging between 16,000 and 16,500 BOE per day, and production in the second half of the year averaging between 22,800 and 23,300 BOE per day. Production in the second quarter has been negatively affected by approximately 2,500 BOE per day as a result of plant outages at the Kaybob KA and K3 facilities, downtime at Utikuma Lake and plant turnarounds affecting Inga and Pedley production. The Company expects to show significant production growth in the second half of the year with new production from the Montney play at Resthaven and production adds from its on-going drilling at Fir/Bigstone and Inga. The Company expects to exit 2011 with production of approximately 24,500 BOE per day, an increase of 41% from fourth quarter 2010 production of 17,385 BOE per day. Average production in 2011 is expected to be weighted 24% oil and 76% gas. However, operating income in 2011 is expected to be weighted 52% oil and 48% gas.

Celtic expects to achieve continued improvement in its cost structure in 2011. Production expense is estimated to be $7.71 per BOE, an improvement of 5% from $8.13 per BOE in 2010. Royalties are expected to average 11.2% compared to 11.5% in 2010. General and administrative expense is estimated to be at industry leading low levels of $0.77 per BOE.

The Company's average commodity price assumptions for 2011 are US$90.00 per barrel for WTI oil, US$4.30 per MMBTU for NYMEX natural gas, $3.55 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US$1.000. These price assumptions have not changed from the Company's previous forecast. These prices compare to average 2010 prices of US$79.43 per barrel for WTI oil, US$4.42 per MMBTU for NYMEX natural gas, $3.95 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US$0.970.

After giving effect to the aforementioned production and commodity price assumptions, funds from operations for 2011 is forecasted to be approximately $156.0 million or $1.58 per share, diluted (previous forecast was $160.0 million or $1.63 per share, diluted) and net loss is forecasted to be approximately $7.5 million or $0.08 per share, diluted.

Changes in forecasted commodity prices and variances in production estimates can have a significant impact on estimated funds from operations and net earnings. Please refer to the advisory regarding forward-looking statements below.

Sensitivities to changes in commodity prices would affect forecasted 2011 funds from operations and net earnings as follows:

(i) Change in AECO natural gas price of $1.00 per GJ would affect funds from operations by $32.0 million ($0.32 per share) and earnings by $23.3 million ($0.24 per share);

(ii) Change in WTI oil price of US$10.00 per barrel would affect funds from operations by $3.8 million ($0.03 per share) and earnings by $2.8 million ($0.02 per share); and

(iii) Change in US/Canadian dollar exchange rate of US$0.05 per CAD would affect funds from operations by $7.9 million ($0.08 per share) and earnings by $5.8 million ($0.06 per share).

Bank debt, net of working capital, is estimated to be $178.4 million by the end of 2011 or approximately 1.1 times forecasted 2011 funds from operations.

Celtic is excited about the growth prospects being generated in the Company and remains optimistic about the Company's ability to deliver continued per share growth in production, reserves, net asset value and funds from operations. Given the Company's strong inventory of drilling locations, we look forward to continued growth in 2011 and beyond.

The information set out herein under the heading "2011 Guidance" is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Celtic's reasonable expectations as to the anticipated results of its proposed business activities for 2011. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

## ADDITIONAL INFORMATION

Additional information relating to Celtic, including the Company's Annual Information Form ("AIF") is filed on SEDAR and can be viewed on their website at www.sedar.com. Copies of the AIF can also be obtained by contacting Sadiq H. Lalani, Vice President, Finance and Chief Financial Officer at Celtic Exploration Ltd., Suite 600, 321 Sixth Avenue SW, Calgary, Alberta, Canada, T2P 3H3. Further information relating to the Company is also available on its website at www.celticex.com.

On behalf of the Board of Directors,

**David J. Wilson**
President and Chief Executive Officer
June 6, 2011

# INTERIM FINANCIAL STATEMENTS

## STATEMENT OF FINANCIAL POSITION

[Unaudited]

| *(CA$ thousands)* | [Notes] | **As at March 31, 2011** | As at December 31, 2010 | As at January 1, 2010 |
|---|---|---|---|---|
| | | | [Note 17] | [Note 17] |
| **ASSETS** | | | | |
| **Current assets** | | | | |
| Cash and cash equivalents | | **10,814** | 644 | 42 |
| Accounts receivable | | **51,964** | 41,535 | 49,252 |
| Drilling royalty credits | [5] | **-** | 2,906 | 13,158 |
| Prepaid expenses and deposits | | **4,777** | 4,871 | 4,947 |
| Derivative financial instruments | [13] | **-** | – | 1,463 |
| **Total current assets** | | **67,555** | 49,956 | 68,862 |
| Deferred income tax asset | | **2,107** | 698 | 510 |
| Other assets | | **6,858** | 5,800 | 6,090 |
| Exploration and evaluation assets | [3] | **67,931** | 67,822 | 39,014 |
| Property, plant and equipment | [4] | **674,041** | 626,070 | 561,926 |
| **Total assets** | | **818,492** | 750,346 | 676,402 |
| **LIABILITIES** | | | | |
| **Current liabilities** | | | | |
| Accounts payable and accrued liabilities | | **107,005** | 89,904 | 61,708 |
| Derivative financial instruments | [13] | **8,429** | 2,633 | 1,757 |
| Bank debt | [6] | **100,000** | 160,800 | 173,900 |
| **Total current liabilities** | | **215,434** | 253,337 | 237,365 |
| Decommissioning obligations | [7] | **26,644** | 25,759 | 21,151 |
| Deferred income tax liability | | **55,878** | 54,843 | 43,370 |
| **Total liabilities** | | **297,956** | 333,939 | 301,886 |
| **SHAREHOLDERS' EQUITY** | | | | |
| Shareholders' capital | [8] | **399,041** | 296,065 | 282,990 |
| Contributed surplus | [8] | **9,930** | 9,449 | 6,798 |
| Retained earnings | | **111,565** | 110,893 | 84,728 |
| **Total shareholders' equity** | | **520,536** | 416,407 | 374,516 |
| **Total liabilities and shareholders' equity** | | **818,492** | 750,346 | 676,402 |
| **Commitments** | [12] | | | |

The accompanying notes form an integral part of these interim financial statements.

On behalf of the Board of Directors:

Director

Director

# STATEMENT OF PROFIT AND COMPREHENSIVE INCOME

[Unaudited]

| *(CA$ thousands, except per share amounts)* | [Notes] | Three months ended March 31, 2011 | 2010 |
|---|---|---|---|
| | | | [Note 17] |
| **Revenue** | | | |
| Oil and gas | | **53,652** | 63,809 |
| Royalties | | **(6,699)** | (9,836) |
| | | **46,953** | 53,973 |
| **Expenses** | | | |
| Production | | **10,105** | 14,410 |
| Transportation | | **625** | 1,052 |
| Financing | | **1,590** | 1,285 |
| General and administrative | | **1,302** | 1,382 |
| Share based compensation | [8] | **1,221** | 720 |
| Depletion, depreciation and amortization | | **32,062** | 28,340 |
| Accretion on decommissioning obligations | | **223** | 197 |
| Asset expiries | [3] | **1,745** | 340 |
| | | **48,873** | 47,726 |
| Loss on derivative financial instruments | [9] | **(6,468)** | (49) |
| Gain on sale of assets | | **9,745** | 29,589 |
| **Profit before taxes** | | **1,357** | 35,787 |
| Deferred income tax expense | [10] | **685** | 9,677 |
| **Profit and comprehensive income** | | **672** | 26,110 |
| **Profit per share** | | | |
| Basic | | **0.01** | 0.29 |
| Diluted | [11] | **0.01** | 0.29 |

The accompanying notes form an integral part of these interim financial statements.

# STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

[Unaudited]

| *(CA$ thousands)* | Shareholders' capital | Contributed surplus | Retained earnings | Total shareholders' equity |
|---|---|---|---|---|
| Balance, December 31, 2010 | **296,065** | **9,449** | **110,893** | **416,407** |
| Profit (loss) | | | **672** | **672** |
| Issue of shares, net of issue costs | **98,482** | | | **98,482** |
| Issue of shares on exercise of stock options | **3,754** | | | **3,754** |
| Share based compensation expense | | **1,221** | | **1,221** |
| Share based compensation settlements | **740** | **(740)** | | **-** |
| Balance, March 31, 2011 | **399,041** | **9,930** | **111,565** | **520,536** |
| | | | | |
| Balance, January 1, 2010 | 282,990 | 6,798 | 84,728 | 374,516 |
| Profit (loss) | | | 26,110 | 26,110 |
| Issue of shares on exercise of stock options | 2,584 | | | 2,584 |
| Share based compensation expense | | 720 | | 720 |
| Share based compensation settlements | 482 | (482) | | - |
| Balance, March 31, 2010 | 286,056 | 7,036 | 110,838 | 403,930 |

The accompanying notes form an integral part of these interim financial statements.

# STATEMENT OF CASH FLOWS

[Unaudited]

| *(CA$ thousands)* | [Notes] | Three months ended March 31, **2011** | 2010 |
|---|---|---|---|
| **Operating activities** | | | |
| Profit (loss) | | **672** | 26,110 |
| Items not affecting cash: | | | |
| Depletion, depreciation and amortization | | **32,062** | 28,340 |
| Accretion on decommissioning obligations | | **223** | 197 |
| Asset expiries | | **1,745** | 340 |
| Share based compensation | | **1,221** | 720 |
| Unrealized loss (gain) on financial instruments | [9] | **5,796** | (712) |
| Gain on sale of assets | | **(9,745)** | (29,589) |
| Provision for (recovery of) deferred income taxes | | **685** | 9,677 |
| Change in non-cash operating working capital | [14] | **(5,422)** | 9,818 |
| **Cash provided by operating activities** | | **27,237** | 44,901 |
| **Financing activities** | | | |
| Decrease in bank debt | | **(60,800)** | (54,800) |
| Issue of common shares, net of costs | [8] | **101,176** | 2,584 |
| **Cash provided by (used in) financing activities** | | **40,376** | (52,216) |
| **Investing activities** | | | |
| Property, plant and equipment expenditures | | **(86,239)** | (47,334) |
| Property, plant and equipment dispositions | | **16,986** | 53,328 |
| Exploration and evaluation asset expenditures | | **(2,208)** | - |
| Settlement of decommissioning obligations | | **(19)** | - |
| Change in other assets | | **(1,058)** | (2,236) |
| Change in non-cash investing working capital | [14] | **15,095** | 3,658 |
| **Cash used in investing activities** | | **(57,443)** | 7,416 |
| **Net change in cash and cash equivalents** | | **10,170** | 101 |
| **Cash and cash equivalents, beginning of period** | | **644** | 42 |
| **Cash and cash equivalents, end of period** | | **10,814** | 143 |

The accompanying notes form an integral part of these interim financial statements.

# NOTES TO THE INTERIM FINANCIAL STATEMENTS

**For the interim periods ended March 31, 2011 and March 31, 2010**
**(All tabular amounts in thousands of Canadian dollars, unless otherwise stated)**

## 1. REPORTING ENTITY AND PRESENTATION OF FINANCIAL STATEMENTS

### NATURE OF BUSINESS

Celtic Exploration Ltd. ("Celtic" or the "Company") was incorporated under the Business Corporations Act (Alberta) on April 16, 2002. Celtic is an oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in Western Canada, primarily in Alberta. The Company's head office is located at 321 - 6th Avenue SW, Suite 600, Calgary, Alberta, T2P 3H3.

### BASIS OF PRESENTATION

In conjunction with the company's annual audited financial statements to be issued under International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), for the year ended December 31, 2011, these interim financial statements have been prepared in accordance with IFRS 1, First-time Adoption of International Financial Reporting Standards and with International Accounting Standard ("IAS") 34, Interim Financial Reporting. Previously, the Company prepared its interim and annual financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP").

The policies applied in these interim financial statements are based on IFRS issued and outstanding as of June 6, 2011, the date the Board of Directors approved the statements. Any subsequent changes to IFRS that are given effect in the Company's annual financial statements for the year ending December 31, 2011 could result in restatement of these interim financial statements, including the transition adjustments recognized on change-over to IFRS.

The preparation of these interim financial statements resulted in changes to Celtic's accounting policies as compared to those disclosed in the Company's annual audited financial statements for the year ended December 31, 2010 issued under previous GAAP. A summary of the significant changes to the Company's accounting policies is disclosed in Note 2, including reconciliations presenting the impact of the transition to IFRS for the comparative periods as at January 1, 2010, as at and for the year ended December 31, 2010 and for the three months ended March 31, 2010, disclosed in Note 17.

### JOINT INTERESTS

A substantial portion of the Company's exploration, development and production activities is conducted jointly with others through unincorporated joint ventures. These financial statements reflect only the Company's proportionate interest of these jointly controlled assets and the proportionate share of the relevant revenue and related costs.

### SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates and affect the results reported in these interim financial statements and could be material. Estimates and underlying assumptions are reviewed on an on-going basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

#### Judgments

In the process of applying Celtic's accounting policies, judgments, apart from those involving estimates, have been made. The following are judgments that may have the most significant effect on the amounts recognized in the financial statements:

### Reserves

Oil and gas assets are depreciated on a unit of production basis at a rate calculated by reference to proved reserves determined in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and incorporating the estimated future cost of developing and extracting those reserves. Proved reserves are estimated using independent reserve engineer reports and represent the estimated quantities of oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainly to be recoverable in future years from known reservoirs and which are considered commercially producible. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is ninety percent likely that the actual remaining quantities recovered will exceed the estimated proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved reserves. The level of estimated reserves is also a key determinant in assessing whether the carrying value of any of the Company's PP&E assets has been impaired.

### Impairment indicators and discount rate

The recoverable amounts of CGUs and individual assets have been determined based on the higher of the present value of value-in-use calculations and discounted fair values less costs to sell. These calculations require the use of estimates and assumptions, including the discount rate. It is reasonably possible that the commodity price assumptions may change, which may then impact the estimated life of the field and economical reserves recoverable and may then require a material adjustment to the carrying value of PP&E. The Company monitors internal and external indicators of impairment relating to its assets.

### Technical feasibility and commercial viability of exploration and evaluation assets

The determination of technical feasibility and commercial viability, based on the presence of proved and probable reserves, results in the transfer of assets from exploration and evaluation ("E&E") assets to PP&E. As discussed above, the estimate of proved and probable reserves is inherently complex and requires significant judgment. Therefore, any material change to reserve estimates could affect the technical feasibility and commercial viability of the underlying assets.

### Valuation of financial instruments

By their very nature, the estimated fair value of derivative financial contracts resulting in derivative financial assets and liabilities are subject to measurement uncertainty.

### Measurement of share-based compensation

Share-based compensation expense recorded pursuant to share-based compensation plans are subject to estimated fair values and forfeiture rates.

### Decommissioning costs

Decommissioning costs will be incurred by the Company at the end of the operating life of the Company's facilities and properties. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques, experience at other production sites, and changes to the risk-free discount rate. The expected timing and amount of expenditure can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

### Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax liabilities recognize the extent that temporary differences will be payable in future periods. The calculation of the liability involves a significant amount of estimation including an evaluation of when the temporary differences will reverse; an analysis of the amount

of future taxable earnings; the availability of cash flows; and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

The Company recognizes the net future tax benefit related to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the net deferred tax assets recorded at the reporting date could be impacted. Additionally, future changes in tax laws in the jurisdictions in which the Company operates could limit the ability of the Company to obtain tax deductions in future periods.

**Contingencies**
By their nature, contingencies will only be resolved when one or more future events occur or fail to occur.

The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

### MEASUREMENT UNCERTAINTY

The amounts recorded for the fair value of financial instruments, share based compensation, depletion, depreciation and accretion of assets, the provision for asset decommissioning obligations and the provision for deferred income taxes are based on estimates. In addition, the impairment test calculation is based on estimates of reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

### BASIS OF MEASUREMENT

All references to dollar amounts in these financial statements and related notes are Canadian dollars, unless otherwise indicated.

These financial statements have been prepared on a historical cost basis, except for certain financial instruments and other financial assets which are carried at fair value.

## 2. SIGNIFICANT ACCOUNTING POLICIES

### CASH AND CASH EQUIVALENTS

Cash and cash equivalents include cash on hand, demand deposits and investments in highly liquid money market instruments which are convertible to known amounts of cash in less than three months.

### FOREIGN CURRENCY

Transactions denominated in foreign currencies are recorded using the exchange rate at the close of the date of the underlying transaction. Monetary assets and liabilities denominated in foreign currencies are translated at the closing rate at the month-end and the gains or losses on re-translation are included in the statement of earnings.

### PROPERTY, PLANT AND EQUIPMENT

Amounts relating to property, plant and equipment ("PP&E"), which primarily consist of oil and gas development and production assets, are measured at cost less accumulated depletion, depreciation and any impairment losses. Development and production assets are accumulated into reserve cost centres and represent the cost of developing the commercial reserves and initiating production.

Capitalized development and production assets generally represent costs incurred in developing reserves and initiating or enhancing production from such reserves. The carrying amount of any replaced or sold component is derecognized.

Development and production costs accumulated within major areas are depleted using the unit-of-production method based on estimated proved reserves before royalties, as determined by independent petroleum reservoir engineers. The depletion base includes capitalized costs, plus future costs to be incurred in developing proved reserves. Corporate assets are depreciated at 25% per annum declining balance.

The carrying amounts of PP&E are grouped into cash generating units ("CGUs") and reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in the statement of profit and comprehensive income.

Impairments of PP&E are assessed each reporting period and are reversed when there has been objective evidence of a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been had no impairment been recognized.

Assets are grouped into CGUs based on separately identifiable and largely independent cash inflows considering geological characteristics, shared infrastructure and exposure to market risks. Estimates of future cash flows used in the calculation of the recoverable amount are based on reserve evaluation reports prepared by independent petroleum reservoir engineers. The recoverable amount is the higher of fair value less cost to sell and the value-in-use. Fair value less cost to sell is derived by estimating the discounted after-tax future net cash flows. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value-in-use is assessed using the expected future cash flows discounted at a pre-tax rate.

**EXPLORATION AND EVALUATION**

Exploration and evaluation ("E&E") assets are comprised of the accumulated expenditures incurred in an area where technical feasibility and commercial viability has not yet been determined and after the legal right to explore has been obtained. E&E assets include costs to acquire undeveloped land; geological and geophysical costs; other direct costs of exploration and directly related general and administrative costs.

Technical feasibility and commercial viability are considered to be determinable when proved reserves are discovered. Upon determination of reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to PP&E.

If and when facts and circumstances indicate that the carrying value of an E&E asset may exceed its recoverable amount, an impairment review is performed. For E&E assets, when there are such indications, an impairment test is carried out by grouping the E&E assets with PP&E CGUs to which they belong for impairment testing. The equivalent combined carrying value of the CGUs is compared against the recoverable amount of the CGUs and any resulting impairment loss is written off. The recoverable amount is the greater of fair value, less costs to sell, or value-in-use.

**OTHER ASSETS**

Other assets are comprised mainly of oilfield equipment, well tubing and casing inventory. Oilfield equipment is valued at the lower of cost and net realizable value. Well tubing and casing inventory is valued at the lower of weighted average cost and net realizable value.

## DECOMMISSIONING OBLIGATIONS

The Company recognizes the present value of a decommissioning obligation in the period in which a legal or constructive obligation exists or when a reliable estimate of the obligation can be made. The obligation is recorded as a liability on a discounted basis using the relevant risk free rate, with a corresponding increase to the carrying amount of the related asset. Over time, the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the underlying proved reserves. Accretion expense is recognized in net earnings. Revisions to the discount rate, estimated timing or amount of future cash flows would also result in an increase or decrease to the decommissioning liability and related asset.

## SHARE BASED COMPENSATION

The Company has a share based compensation plan and uses the fair value method to record compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant and a provision for the costs is provided for as contributed surplus over the service period. The consideration received by the Company on the exercise of stock options is recorded as an increase to share capital together with corresponding amounts previously recognized in contributed surplus.

## INCOME TAXES

The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate deferred income tax assets or liabilities. Deferred income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Deferred income tax assets and liabilities are presented as non-current. Tax on income in interim periods is accrued using the tax rate that would be applicable to expected total annual earnings.

## FINANCIAL INSTRUMENTS

### Financial assets and liabilities

Financial assets and financial liabilities are recognized when the Company becomes a party to the contractual provisions that define the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership. Financial assets and financial liabilities are offset and the net amount reported in the Statement of Financial Position when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis or realize the asset and settle the liability simultaneously. Financial assets and financial liabilities are initially recognized at fair value. This initial fair value is normally the transaction price plus, in the case of financial assets not at fair value through profit (loss), directly attributable transaction costs.

The subsequent measurement of the Company's financial instruments depends on their classification determined by the purpose for which the instruments were acquired, as follows:

### Financial assets and liabilities held-for-trading

Derivative financial contracts and the investment in marketable securities are classified as held-for-trading. These assets are carried on the Statement of Financial Position at fair value with gains or losses recognized in profit (loss) in the period in which they arise. Financial assets and liabilities held-for-trading are classified as current except for the portion expected to be realized or paid beyond twelve months from the Statement of Financial Position date, which is classified as non-current.

### Available-for-sale investments

Available-for-sale investments are those non-derivative financial assets that are not classified as loans and receivables and are initially recognized at fair value plus transaction costs. After initial recognition, available-for-sale financial assets are measured at fair value, with gains or losses recognized within other comprehensive income (loss). Available-for-sale investments are classified

as non-current, unless the investments mature within twelve months, or management expects to dispose of them within twelve months. The Company has no available-for-sale investments.

**Loans and receivables**

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are carried at amortized cost using the effective interest rate method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process. The Company's loans and receivables are comprised of trade and other receivables which are included in current assets due to their short-term nature, the reclamation fund and cash and cash equivalents.

**Other financial liabilities at amortized cost**

Financial liabilities at amortized cost include trade and other payables and bank debt. Trade and other payables are initially recognized at the amount required to be paid less, when material, a discount to reduce the payables to fair value. Subsequently, trade and other payables are measured at amortized cost using the effective interest rate method. Bank debt is recognized initially at fair value, net of any transaction costs incurred and subsequently at amortized cost using the effective interest rate method. Financial liabilities are classified as current liabilities if payment is due within twelve months. Otherwise, they are presented as non-current liabilities.

**Derivative financial contracts**

The Company uses derivative financial instruments to manage its exposure to movements in commodity prices and interest rates, which include crude oil and natural gas commodity contracts and interest rate swaps ("derivative financial contracts"). These instruments are not used for trading or speculative purposes. Derivative financial contracts are initially recognized at fair value on the date a derivative contract is entered into and are re-measured at their fair value at each subsequent reporting date. Derivative financial contracts are carried as assets when their fair value is positive and as liabilities when the fair value is negative. Transaction costs are recognized in profit or loss when incurred. The Company has not designated its derivative financial contracts as effective accounting hedges and therefore, has not applied hedge accounting.

## REVENUE RECOGNITION

Revenue includes the sale of crude oil, natural gas, natural gas liquids and sulphur and is recorded when all of the following conditions are satisfied, which is generally at the time the product enters the pipeline:

- the significant risks and rewards of ownership of the product are transferred to the buyer, which is usually when legal title passes to the external party;
- the Company retains neither continuing managerial involvement to the degree usually associated with ownership nor effective control over the products sold;
- the amount of revenue can be reliably measured;
- it is probable that the economic benefits associated with the transaction will flow to the entity; and
- the costs incurred or to be incurred in respect of the transaction can be measured reliably.

Revenue from the production of oil and natural gas from properties in which the Company has an interest with joint venture partners are recognized on the basis of the Company's working interest in those properties. Revenue is measured net of discounts, customs duties and royalties. With respect to the latter, the entity is acting as a collection agent on behalf of others.

## LEASES

Agreements under which payments are made to owners in return for the right to use an asset for a period are accounted for as leases. All of the Company's leases are treated as operating leases and the costs are recognized in earnings on a straight line basis.

## COMPREHENSIVE INCOME

Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources and other comprehensive income comprises revenues, expenses, gains and losses that, in accordance with IFRS, are recognized in comprehensive income but excluded from net earnings.

## PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Weighted average number of shares is determined by relating the portion of time within the reporting period that common shares have been outstanding to the total time in that period.

Diluted per share amounts are calculated using the treasury stock method which assumes that any proceeds obtained on exercise of share options or other dilutive instruments would be used to purchase common shares at the average market price during the period. The treasury stock method also assumes that the deemed proceeds related to unrecognized share based compensation expense are used to purchase shares at the weighted average trading price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

## CHANGES IN ACCOUNTING POLICIES AND PRACTICES

March 31, 2011 is the first reporting date that Celtic is reporting under IFRS (refer Note 1 and Note 17). Accounting standards, issued up to June 6, 2011, for periods beginning on or after January 1, 2011 have been adopted as part of the transition to IFRS.

### Pending Accounting Pronouncements

*IFRS 9, Financial Instruments*

IFRS 9 was issued in November 2009. This standard is the first step in the process to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 introduces new requirements for classifying and measuring financial assets and liabilities, which may affect the Company's accounting for its financial assets. The standard is not applicable until January 1, 2013 but is available for early adoption. The Company has yet to assess the full impact of IFRS 9.

*IFRS 10, Consolidation*

IFRS 10 was issued on May 12, 2011. This standard requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12, Consolidation—Special Purpose Entities, and parts of IAS 27, Consolidated and Separate Financial Statements. The standard is not applicable until January 1, 2013 but is available for early adoption. The Company has yet to assess the full impact of IFRS 10.

*IFRS 11, Joint Arrangements*

IFRS 11 was issued on May 12, 2011. This standard requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures, and SIC-13, Jointly Controlled Entities—Non-monetary Contributions by Venturers. The standard is not applicable until January 1, 2013 but is available for early adoption. The Company has yet to assess the full impact of IFRS 11.

*IFRS 12, Disclosure of Interests in Other Entities*

IFRS 12 was issued on May 12, 2011. This standard establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities. The standard is not applicable until January 1, 2013 but is available for early adoption. The Company has yet to assess the full impact of IFRS 12.

*IFRS 13, Fair Value Measurement*

IFRS 13 was issued on May 12, 2011. This is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. The standard is not applicable until January 1, 2013 but is available for early adoption. The Company has yet to assess the full impact of IFRS 13.

*Amendments to Other Standards*

In addition, there have been amendments to existing standards, including IAS 27, Separate Financial Statements, and IAS 28, Investments in Associates and Joint Ventures. IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 to 13. Both of the amended standards are not applicable until January 1, 2013 but are available for early adoption. The Company has yet to assess the full impact of these amendments.

## 3. EXPLORATION AND EVALUATION ASSETS

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Exploration and evaluation assets, at cost | $ 68,877 | $ 70,080 |
| Expiries | (946) | (2,258) |
| Net carrying amount | $ 67,931 | $ 67,822 |

The following table reconciles movements of exploration and evaluation assets during the period:

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Net carrying amount, beginning of period | $ 67,822 | $ 39,014 |
| Additions | 2,208 | 37,190 |
| Dispositions | (609) | (6,124) |
| Transfers from (to) PP&E | (544) | - |
| Expiries | (946) | (2,258) |
| Net carrying amount, end of period | $ 67,931 | $ 67,822 |

Exploration and evaluation assets consist of the Company's undeveloped land and exploration projects which are pending the determination of technical feasibility.

## 4. PROPERTY, PLANT AND EQUIPMENT

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Development and production assets, at cost | $ 1,154,795 | $ 1,083,364 |
| Corporate assets, at cost | 2,321 | 2,294 |
| Property, plant and equipment, at cost | $ 1,157,116 | $ 1,085,658 |
| Accumulated depletion, depreciation and amortization | (483,075) | (459,588) |
| Net carrying amount | $ 674,041 | $ 626,070 |

The following table reconciles movements of property, plant and equipment during the period:

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Net carrying amount, beginning of period | $ 626,070 | $ 561,926 |
| Additions | 88,861 | 209,306 |
| Dispositions | (9,372) | (25,016) |
| Transfers from (to) E&E | 544 | – |
| Depletion, depreciation and amortization | (32,062) | (120,146) |
| Net carrying amount, end of period | $ 674,041 | $ 626,070 |

Future capital costs required to develop proved reserves in the amount of $104.9 million (2010 – $90.5 million) are included in the depletion and depreciation calculation.

## 5. DRILLING ROYALTY CREDITS

The Drilling Royalty Credit ("DRC") program introduced by the Alberta government in 2009 provides companies with a $200 per metre credit on wells drilled. These credits can be applied against corporate Crown royalties payable during the period from April 1, 2009 to March 31, 2011, subject to a maximum of 50% of corporate Crown royalties for Celtic. Credits earned are recorded as a reduction of property, plant and equipment, with reasonable assurance that credits can be claimed in a future period.

The following table reconciles movements of drilling royalty credits during the period:

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Drilling royalty credits, beginning of period | $ 2,906 | $ 13,158 |
| Credits earned through drilling | 8,600 | 30,582 |
| Credits claimed | (2,034) | (11,533) |
| Credits deemed un-claimable | (9,472) | (29,301) |
| Drilling royalty credits, end of period | – | $ 2,906 |

## 6. BANK DEBT

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada. The authorized borrowing amount under this facility as at March 31, 2011 is $215.0 million. The facilities are available for a period of 364 days, maturing on June 28, 2011 and may be extended for an additional 364 days. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Covenants include a current ratio test, reporting requirements, permitted indebtedness, permitted dispositions, permitted hedging, permitted encumbrances and other standard business operating covenants. The authorized borrowing amount is subject to interim reviews by the financial institutions. As at March 31, 2011, the Company is in compliance with all covenants. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of $500.0 million and general assignment of book debts.

The following table summarizes bank debt outstanding:

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Bank loan | $ – | $ 30,800 |
| Bankers' acceptances | 100,000 | 130,000 |
| Bank debt | $ 100,000 | $ 160,800 |

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime plus 1.25% to bank prime plus 3.25%, depending upon the Company's then current debt to cash flow ratio of between less than one and one tenth times to greater than three times. Under the credit facility, borrowings through the use of bankers' acceptances are also available. Stamping fees fluctuate based on a pricing grid and range from 2.25% to 4.25%, depending upon the Company's then current debt to cash flow ratio of between less than one and one tenth times to greater than three times.

The Company has entered into an interest rate swap transaction whereby borrowings through bankers' acceptances in the amount of $100.0 million has been fixed at an annual interest rate of 2.07% from April 22, 2010 to April 21, 2011, before bank stamping fees.

## 7. DECOMMISSIONING OBLIGATIONS

The following table provides a reconciliation of the carrying amount of the obligation associated with the retirement of oil and gas properties:

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Decommissioning obligations, beginning of year | $ 25,759 | $ 21,151 |
| Liabilities incurred | 3,418 | 4,363 |
| Liabilities disposed | (2,737) | (2,347) |
| Liabilities settled | (19) | (1,897) |
| Revisions to estimated liabilities | – | 3,736 |
| Accretion expense | 223 | 753 |
| Decommissioning obligations, end of year | $ 26,644 | $ 25,759 |

The key assumptions, on which the carrying amount of the decommissioning obligations is based, include a risk-free rate of 2.1 to 4.6% (2010 - 1.7 to 4.6%) and an inflation rate of 2.7% (2010 - 2.7%). The total undiscounted amount of the estimated cash flows required to settle the obligations is $36.5 million (December 31, 2010 - $33.2 million). The inflated value of estimated cash flows required to settle the obligations at a future period at the time the asset is retired is $76.8 million (December 31, 2010 - $71.6 million). The expected timing of payment of the cash flows required to settle the obligations ranges from 1 year to 50 years.

## 8. SHARE CAPITAL

### (a) Authorized

Unlimited number of common shares and preferred shares.

### (b) Issued

The following table summarizes the changes in common shares outstanding:

| | Common shares | Amount |
|---|---|---|
| Balance, December 31, 2009 | 89,125 | $ 282,990 |
| Issued for cash on exercise of stock options | 1,751 | 11,060 |
| Amount relating to exercised options previously recorded as contributed surplus | – | 2,015 |
| Balance, December 31, 2010 | 90,876 | $ 296,065 |
| Issued for cash on exercise of stock options | 573 | 3,754 |
| Amount relating to exercised options previously recorded as contributed surplus | – | 740 |
| Issued for cash through public prospectus offering | 5,000 | 101,500 |
| Share issue costs, after deferred income taxes | – | (3,018) |
| Balance, March 31, 2011 | 96,449 | $ 399,041 |

### (c) Common share offerings

In March 2011, Celtic issued 5.0 million common shares by way of a short form prospectus at an issue price of $20.30 per share for gross proceeds of $101.5 million. In conjunction with this offering, the Company provided the syndicate of underwriters an over-allotment option to purchase an additional 0.75 million common shares at a price of $20.30 per share exercisable prior to April 30, 2011 (see Note 16 entitled Subsequent Event).

### (d) Stock options

Celtic has a stock option plan that provides for granting of stock options to directors, officers, employees and certain consultants. Stock options granted under the stock option plan have a maximum term of five years to expiry. Vesting is determined by the Company's board of directors. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange at the time of grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

The following table summarizes the changes in stock options outstanding:

| | Number of options | Average exercise price |
|---|---|---|
| Balance, December 31, 2009 | 6,616 | $ 6.95 |
| Granted | 2,049 | 10.70 |
| Exercised | (1,751) | 6.32 |
| Forfeited/cancelled | (365) | 6.97 |
| Balance, December 31 2010 | 6,549 | $ 8.31 |
| Granted | – | – |
| Exercised | (573) | 6.55 |
| Forfeited | – | – |
| Balance, March 31, 2011 | 5,976 | $ 8.48 |

The Company uses the fair value method to record stock based compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

| | Three months ended March 31, 2011 | Twelve months ended December 31, 2010 |
|---|---|---|
| Risk free interest rate | – | 1.95% |
| Expected life (years) | – | 3.1 |
| Expected volatility | – | 43.4% |
| Expected dividend yield | – | – |
| Fair value of options granted during the year ($/share) | – | $ 3.35 |

There were no stock options granted during the three month period ended March 31, 2011.

The following table summarizes information regarding stock options outstanding at March 31, 2011:

| Range of exercise prices per share | Number of options outstanding | Weighted average remaining term in years | Weighted average exercise price per share for options outstanding | Number of options exercisable | Weighted average exercise price per share for options exercisable |
|---|---|---|---|---|---|
| $5.01 to $7.00 | 1,778 | 1.7 | $ 6.19 | 1,505 | $ 6.22 |
| $7.01 to $9.00 | 1,973 | 2.7 | $ 8.04 | 1,037 | $ 8.13 |
| $9.01 to $11.00 | 2,092 | 4.0 | $ 10.49 | 72 | $ 10.15 |
| $11.01 to $13.00 | 78 | 4.4 | $ 12.39 | – | – |
| $13.01 to $17.00 | 55 | 4.7 | $ 16.18 | – | – |
| Total | 5,976 | 2.9 | $ 8.48 | 2,614 | $ 7.09 |

## 9. GAIN (LOSS) ON FINANCIAL INSTRUMENTS

The following table reconciles gains (losses) on financial instruments:

| Three months ended March 31 | 2011 | 2010 |
|---|---|---|
| Realized gain (loss) | $ (672) | $ (761) |
| Unrealized gain (loss) | (5,796) | 712 |
| Gain (loss) on financial instruments | $ (6,468) | $ (49) |

## 10. INCOME TAXES

The provision for income taxes differs from the expected amount calculated by applying the combined Federal and Provincial corporate income tax rate as a result of the following:

| Three months ended March 31 | 2011 | 2010 |
|---|---|---|
| Profit before taxes | $ 1,357 | $ 35,787 |
| Statutory combined federal & provincial income tax rate | 26.50% | 28.00% |
| Expected income taxes | $ 360 | $ 10,020 |
| Increase (decrease) resulting from: | | |
| Non-deductible share based compensation expense | 324 | 202 |
| Other adjustments | 1 | (545) |
| Provision for deferred income taxes | $ 685 | $ 9,677 |

## 11. PROFIT PER SHARE

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under this method, only "in-the-money" dilutive instruments impact the calculations in computing diluted profit per share.

In computing diluted profit per share, 3.3 million (2010 – 1.8 million) shares were added to the 91.4 million (2010 – 89.4 million) weighted average number of common shares outstanding during the three month period for the dilutive effect of stock options. For the purpose of calculating the diluted net loss per share for the period ended March 31, 2011, the incremental shares from assumed exercise of stock options are not included due to their anti-dilutive effect.

## 12. COMMITMENTS

The Company is committed to future payments under the following agreements:

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|
| Operating lease – office building | $ 267 | $ 530 | $ 530 | $ 530 | $ 530 | $ 221 | $ 2,608 |
| Operating lease – vehicles | 141 | 93 | 50 | 4 | - | - | 288 |
| Firm transportation agreements | 14 | - | - | - | - | - | 14 |
| | $ 422 | $ 623 | $ 580 | $ 534 | $ 530 | $ 221 | $ 2,910 |

Office building operating lease relates to rental office space in Calgary, Alberta. The current lease expires on May 31, 2016.

At March 31, 2011, the Company had bank debt outstanding in the amount of $100.0 million. The Company has a $215.0 million term credit facility that is available on a revolving basis until June 28, 2011. Commencing on June 28, 2011, the Company may request the facility be available on a non-revolving basis for a period of one year thereafter, subject to approval by lenders with commitments of at least two thirds of the credit facility amount.

## 13. FINANCIAL INSTRUMENTS

### (a) Fair values of financial assets and liabilities

Financial assets and liabilities of the Company consist mainly of cash and cash equivalents, deposits, drilling royalty credits, receivables, payables, bank debt and assets and liabilities arising from the use of financial instrument risk management contracts, all of which are included in these financial statements.

Celtic's financial risk management contracts are transacted in active markets. The Company classifies the fair value of these transactions according to the following fair value hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 – Values are based on unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date.
- Level 2 – Values are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace. Prices in Level 2 are either directly or indirectly observable as of the reporting date.
- Level 3 – Values are based on prices or valuation techniques that are not based on observable market data.

Accordingly, Celtic's financial derivative instruments are classified as Level 2 Inputs. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

The following table presents the Company's fair value measurements for each hierarchy level as at March 31, 2011:

| | Level 1 inputs | Level 2 inputs | Level 3 inputs | Total |
|---|---|---|---|---|
| Crude oil swaps | – | $ (8,355) | – | $ (8,355) |
| Interest rate swaps | – | (74) | – | (74) |
| Net asset (liability) | – | $ (8,429) | – | $ (8,429) |

At March 31, 2011, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

| | Carrying amount | Fair value |
|---|---|---|
| Loans and receivables | | |
| (cash, accounts receivable, drilling royalty credits and deposits) | $ 66,987 | $ 66,987 |
| Held-for-trading instruments (financial instruments) | (8,429) | (8,429) |
| Other financial liabilities (accounts payable and bank debt) | (207,005) | (207,005) |
| Total | $ (148,447) | $ (148,447) |

At December 31, 2010, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

| | Carrying amount | Fair value |
|---|---|---|
| Loans and receivables | | |
| (cash, accounts receivable, drilling royalty credits and deposits) | $ 49,294 | $ 49,294 |
| Held-for-trading instruments (financial instruments) | (2,633) | (2,633) |
| Other financial liabilities (accounts payable and bank debt) | (250,704) | (250,704) |
| Total | $ (204,043) | $ (204,043) |

**(b) Credit risk**

The majority of the Company's accounts receivable is in respect of oil and gas operations. Celtic generally extends unsecured credit to these third parties, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk.

The ageing of the Company's accounts receivable is summarized in the following table:

| | Current | 31 - 60 days | 61 - 90 days | Over 90 days | Total |
|---|---|---|---|---|---|
| March 31, 2011 | | | | | |
| Accounts receivable | $ 46,332 | $ 299 | $ 2,517 | $ 2,816 | $ 51,964 |
| December 31, 2010 | | | | | |
| Accounts receivable | $ 34,437 | $ 2,034 | $ 648 | $ 4,416 | $ 41,535 |

Celtic has not experienced any material credit loss in the collection of receivables in 2011 and 2010.

**(c) Interest rate risk**

The Company is exposed to fluctuations in interest rates on its bank debt. Interest rate risk is mitigated through short-term fixed rate borrowings using bankers' acceptances and interest rate swap transactions.

The Company has entered into an interest rate swap transaction whereby the interest rate applicable to borrowings by way of bankers' acceptances has been fixed. Borrowings in the amount of $100.0 million have been fixed at an annual interest rate of 2.1% from April 22, 2010 to April 21, 2011, before bank stamping fees. The fair value of the remaining term of this contract, mark-to-market at March 31, 2011 is a liability of $74,000. If annual interest rates increase (decrease) by 1%, the fair market value of the remaining term of this contract would increase (decrease) by $58,000.

**(d) Foreign exchange rate risk**

The Company is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices.

In order to mitigate a portion of the risk relating to revenue that is subject to fluctuations in the exchange rate, the Company has entered into commodity swap transactions whereby commodity prices denominated in U.S. dollars have been converted to Canadian dollars as described under the heading "Commodity price risk management" below.

**(e) Commodity price risk management**

The following is a summary of NYMEX West Texas Intermediate ("WTI") light sweet oil fixed price contracts in effect at March 31, 2011:

| Daily quantity | Remaining term of contract | Fixed price per bbl |
|---|---|---|
| 2,000 bbls per day | April 1 to December 31, 2011 | CA$ 90.90 |

The fair value of the remaining term of the above crude oil contracts, mark-to-market at March 31, 2011 is a liability of $8.4 million. If the WTI price increases (decreases) by $1.00 per bbl, the fair market value of these contracts would increase (decrease) by $550,000.

**(f) Liquidity risk**

Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company's financial liabilities are comprised of accounts payable, accrued liabilities and bank debt.

The Company manages liquidity risk through the prudent use of debt, interest rate, currency and commodity price risk management and through an actively managed production and capital expenditure budget process.

Celtic has a committed credit facility which matures on June 28, 2011 and may be extended for an additional 364 days with the consent of the lenders. An interim review was conducted by the financial institutions in the fourth quarter of 2010 and the borrowing base of $215.0 million was reconfirmed. Although management expects that the financial institutions will extend the facility in 2011, there can be no assurance that the financial institutions will choose to do so. Should the financial institutions not extend the loan, the Company would need to seek alternative sources of debt or equity financing or dispose of certain assets to repay the outstanding indebtedness.

**(g) Capital structure**

The Company's capital structure is comprised of shareholders' equity, bank debt and working capital. Celtic's objectives when managing its capital structure is to maintain financial flexibility in order to meet financial obligations, as well as to finance future growth through capital expenditures relating to exploration, development and acquisition activities.

The Company monitors its capital structure and short-term financing requirements using a net debt to trailing funds from operations ratio, a non-IFRS financial measure.

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Bank debt | $ 100,000 | $ 160,800 |
| Working capital deficiency (1) | 47,879 | 42,581 |
| Net debt | $ 147,879 | $ 203,381 |
| Trailing funds from operations (2) | $ 130,636 | $ 122,500 |
| Net debt to trailing funds from operations ratio | 1.13 | 1.66 |

(1) Working capital excludes bank debt.

(2) Trailing funds from operations is annualized based on the most recent quarter's funds from operations which is calculated as cash provided by operating activities, before change in non-cash operating working capital.

Celtic targets a net debt to trailing funds from operations ratio of less than 2.0 times. The Company manages its capital structure and makes adjustments according to market conditions in order to maintain flexibility to achieve its objectives stated above. To adjust its capital structure, the Company may increase or decrease capital expenditures, issue new shares, issue new debt or repay existing debt.

## 14. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital, excluding bank debt:

| Three months ended March 31 | | 2011 | | 2010 |
|---|---|---|---|---|
| Accounts receivable | $ | (10,428) | $ | 2,681 |
| Drilling royalty credits | | 2,906 | | (7,718) |
| Prepaid expenses and deposits | | 94 | | 357 |
| Accounts payable and accruals | | 17,101 | | 18,156 |
| Change in non-cash working capital | $ | 9,673 | $ | 13,476 |
| Relating to: | | | | |
| Operating activities | $ | (5,422) | $ | 9,818 |
| Investing activities | | 15,095 | | 3,658 |
| Change in non-cash working capital | $ | 9,673 | $ | 13,476 |

During the reporting period, the Company made the following cash outlays in respect of interest expense:

| Three months ended March 31 | | 2011 | | 2010 |
|---|---|---|---|---|
| Interest | $ | 1,550 | $ | 1,043 |

## 15. RELATED-PARTY TRANSACTIONS

The Company has retained the law firm of Borden Ladner Gervais LLP ("BLG") to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic is a partner of this law firm. During the three months ended March 31, 2011, the Company incurred $0.1 million (2010 - $0.1 million) to BLG for legal fees and disbursements. The Company expects to continue using the services of this law firm from time to time.

## 16. SUBSEQUENT EVENT

On April 26, 2011, Celtic issued 750,000 common shares at a price of $20.30 per share, resulting in gross proceeds of $15.2 million pursuant to the exercise of an over-allotment option that was granted to a syndicate of underwriters in connection with the Company's bought deal short-form prospectus offering dated March 31, 2011.

## 17. TRANSITION TO IFRS

The Company's financial statements for the year ending December 31, 2011 will be the first annual financial statements that will be prepared in accordance with IFRS. These interim financial statements were prepared as described in Note 1, including the application of IFRS 1, *First-time Adoption of International Financial Reporting Standards*. Prior to the adoption of IFRS, the Company followed Canadian GAAP.

Comparative financial information is required on first time adoption of IFRS and therefore the Company has adopted IFRS as at January 1, 2010 (the "Transition Date"). IFRS generally requires full retrospective application of the standards in effect; however, IFRS 1 provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions to this requirement.

The Company has applied the following optional exemptions:

**Full cost oil and gas accounting** – IFRS 1 provides the option for entities using full cost accounting for oil and gas activities under previous GAAP to measure oil and gas assets at the Transition Date at the historical net book value or at fair value, rather than applying IFRS rules retrospectively. The Company elected to measure its oil and gas assets at the net book value determined under previous GAAP, resulting in undeveloped land costs being reclassified to E&E assets. The remaining development and production assets that were accumulated in a country cost centre under previous GAAP could be allocated to the cost centre's underlying assets pro-rata using reserve volumes or values. The Company elected to allocate these assets using reserve values.

**Decommissioning obligations** – For entities taking the *Full Cost Oil and Gas Accounting* exemption above, IFRS 1 requires that entities measure decommissioning obligations in accordance with IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*, as at the Transition Date and that any difference between this amount and the carrying amount of those liabilities determined under the Company's previous GAAP, be recognized directly in retained earnings.

**Share based payments** – IFRS 2, *Share-based Payments*, requires retrospective application of its provisions to equity instruments granted after November 7, 2002. The IFRS 1 exemption allows first-time adopters to not apply IFRS 2 to equity instruments that were granted prior to November 7, 2002. It also allows the first-time adopter to not apply IFRS 2 to equity instruments granted after November 7, 2002 that vested before the Transition Date. The Company elected to use these exemptions provided under IFRS 1.

**Borrowing costs** – the Company has taken the election to apply *IAS 23, Borrowing Costs* as of the Transition Date.

The following are reconciliations of the financial statements presented under previous GAAP to the amended financial statements prepared under IFRS.

**RECONCILIATION OF STATEMENT OF FINANCIAL POSITION AS AT JANUARY 1, 2010**

| *(CA$ thousands)* | Previous GAAP | Reclass | IFRS Adjustments DO (2) | SBC (3) | PP&E (4) | IFRS |
|---|---|---|---|---|---|---|
| | | [Note 17 a] | [Note 17 d] | [Note 17 e] | [Note 17 b, c] | |
| **ASSETS** | | | | | | |
| Current assets | | | | | | |
| Cash and cash equivalents | 42 | | | | | 42 |
| Accounts receivable | 49,252 | | | | | 49,252 |
| Drilling royalty credits | 13,158 | | | | | 13,158 |
| Prepaid expenses and deposits | 4,947 | | | | | 4,947 |
| Fair value of financial instruments | 1,463 | | | | | 1,463 |
| Future income tax asset | 510 | (510) | | | | – |
| Total current assets | 69,372 | (510) | – | – | – | 68,862 |
| Deferred income tax asset | – | 510 | | | | 510 |
| Other assets | 6,090 | | | | | 6,090 |
| Exploration and evaluation assets | – | | | | 39,014 | 39,014 |
| Property, plant and equipment | 603,308 | | | | (41,382) | 561,926 |
| Total assets | 678,770 | – | – | – | (2,368) | 676,402 |
| **LIABILITIES** | | | | | | |
| Current liabilities | | | | | | |
| Accounts payable and accrued liabilities | 61,708 | | | | | 61,708 |
| Fair value of financial instruments | 1,757 | | | | | 1,757 |
| Future income tax liability | 424 | (424) | | | | – |
| Bank debt | 173,900 | | | | | 173,900 |
| Total current liabilities | 237,789 | (424) | – | – | – | 237,365 |
| Decommissioning obligations (1) | 6,588 | | 14,563 | | | 21,151 |
| Deferred income tax liability (1) | 47,203 | 424 | (3,641) | | (616) | 43,370 |
| Total liabilities | 291,580 | – | 10,922 | – | (616) | 301,886 |
| **SHAREHOLDERS' EQUITY** | | | | | | |
| Shareholders' capital | 282,990 | | | | | 282,990 |
| Contributed surplus | 5,300 | | | 1,498 | | 6,798 |
| Retained earnings | 98,900 | | (10,922) | (1,498) | (1,752) | 84,728 |
| Total shareholders' equity | 387,190 | – | (10,922) | – | (1,752) | 374,516 |
| Total liabilities and shareholders' equity | 678,770 | – | – | – | (2,368) | 676,402 |

(1) Caption has been renamed to comply with the financial statement presentation under IFRS.

(2) Decommissioning obligations has been abbreviated as "DO".

(3) Share based compensation has been abbreviated as "SBC".

(4) Property, plant and equipment has been abbreviated as "PP&E".

## RECONCILIATION OF STATEMENT OF PROFIT AND COMPREHENSIVE INCOME FOR THE THREE MONTHS ENDED MARCH 31, 2010

| *(CA$ thousands, except per share amounts)* | Previous GAAP | Reclass | IFRS Adjustments DO [2] | SBC [3] | E&E/PP&E [4] | IFRS |
|---|---|---|---|---|---|---|
| | | [Note 17 a] | [Note 17 d] | [Note 17 e] | [Note 17 b,c] | |
| Revenue | | | | | | |
| Oil and gas | 63,809 | | | | | 63,809 |
| Royalties | (9,836) | | | | | (9,836) |
| | 53,973 | – | – | – | – | 53,973 |
| Expenses | | | | | | |
| Production | 14,410 | | | | | 14,410 |
| Transportation | 1,052 | | | | | 1,052 |
| Interest and financing | 1,285 | | | | | 1,285 |
| General and administrative | 1,382 | | | | | 1,382 |
| Share based compensation | 527 | | | 193 | | 720 |
| Depletion, depreciation and amortization | 27,271 | (86) | | | 1,155 | 28,340 |
| Accretion on decommissioning obligations [1] | – | 86 | 111 | | | 197 |
| Asset expiries | – | | | | 340 | 340 |
| | 45,927 | – | 111 | 193 | 1,495 | 47,726 |
| Loss on financial instruments [1] | – | (49) | | | | (49) |
| Realized gain (loss) on financial instruments | (761) | 761 | | | | – |
| Unrealized gain (loss) on financial instruments | 712 | (712) | | | | – |
| Gain on sale of capital assets | – | | | | 29,589 | 29,589 |
| Profit (loss) before taxes | 7,997 | – | (111) | (193) | 28,094 | 35,787 |
| Deferred income tax (recovery) | 2,392 | | (28) | | 7,313 | 9,677 |
| Profit (loss) and comprehensive income (loss) | 5,605 | – | (83) | (193) | 20,781 | 26,110 |
| Profit per share | | | | | | |
| Basic | 0.06 | | | | | 0.29 |
| Diluted | 0.06 | | | | | 0.29 |

(1) Caption has been renamed to comply with the financial statement presentation under IFRS.

(2) Decommissioning obligations has been abbreviated as "DO".

(3) Share based compensation has been abbreviated as "SBC".

(4) Exploration and evaluation assets has been abbreviated as "E&E" and property, plant and equipment has been abbreviated as "PP&E".

## RECONCILIATION OF STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY AS AT MARCH 31, 2010

| *(CA$ thousands)* | Previous GAAP | January 1, 2010 adjustments | IFRS Adjustments | | | IFRS |
|---|---|---|---|---|---|---|
| | | | DO [2] | SBC [3] | PP&E [4] | |
| | | | [Note 17 d] | [Note 17 e] | [Note 17 b] | |
| **SHAREHOLDERS' EQUITY** | | | | | | |
| Shareholders' capital | 286,056 | | | | | 286,056 |
| Contributed surplus | 5,345 | 1,498 | | 193 | | 7,036 |
| Retained earnings and AOCI [1] | 104,505 | (14,172) | (83) | (193) | 20,781 | 110,838 |
| Total shareholders' equity | 395,906 | (12,674) | (83) | – | 20,781 | 403,930 |

(1) Accumulated other comprehensive income has been abbreviated as "AOCI".

(2) Decommissioning obligations has been abbreviated as "DO".

(3) Share based compensation has been abbreviated as "SBC".

(4) Property, plant and equipment has been abbreviated as "PP&E".

## RECONCILIATION OF STATEMENT OF FINANCIAL POSITION AS AT DECEMBER 31, 2010

| *(CA$ thousands)* | Previous GAAP | Reclass | IFRS Adjustments DO [2] | SBC [3] | PP&E [4] | IFRS |
|---|---|---|---|---|---|---|
| | | [Note 17 a] | [Note 17 d] | [Note 17 e] | [Note 17 b] | |
| **ASSETS** | | | | | | |
| Current assets | | | | | | |
| Cash and cash equivalents | 644 | | | | | 644 |
| Accounts receivable | 41,535 | | | | | 41,535 |
| Drilling royalty credits | 2,906 | | | | | 2,906 |
| Prepaid expenses and deposits | 4,871 | | | | | 4,871 |
| Future income tax asset | 698 | (698) | | | | - |
| Total current assets | 50,654 | (698) | - | - | - | 49,956 |
| Deferred income tax asset | - | 698 | | | | 698 |
| Other assets | 5,800 | | | | | 5,800 |
| Exploration and evaluation assets | 0 | | | | 67,822 | 67,822 |
| Property, plant and equipment | 666,571 | | 2,605 | | (43,106) | 626,070 |
| Total assets | 723,025 | - | 2,605 | - | 24,716 | 750,346 |
| **LIABILITIES** | | | | | | |
| Current liabilities | | | | | | |
| Accounts payable and accrued liabilities | 89,904 | | | | | 89,904 |
| Fair value of financial instruments | 2,633 | | | | | 2,633 |
| Future income tax liability | - | | | | | - |
| Bank debt | 160,800 | | | | | 160,800 |
| Total current liabilities | 253,337 | - | - | - | - | 253,337 |
| Decommissioning obligations [1] | 9,919 | | 15,840 | | | 25,759 |
| Deferred income tax liability [1] | 51,674 | | (3,309) | | 6,478 | 54,843 |
| Total liabilities | 314,930 | - | 12,531 | - | 6,478 | 333,939 |
| **SHAREHOLDERS' EQUITY** | | | | | | |
| Shareholders' capital | 296,065 | | | | | 296,065 |
| Contributed surplus | 6,547 | | | 2,902 | | 9,449 |
| Retained earnings | 105,483 | | (9,927) | (2,902) | 18,239 | 110,893 |
| Total shareholders' equity | 408,095 | - | (9,927) | - | 18,239 | 416,407 |
| Total liabilities and shareholders' equity | 723,025 | - | 2,604 | - | 24,717 | 750,346 |

(1) Caption has been renamed to comply with the financial statement presentation under IFRS.

**RECONCILIATION OF STATEMENTS OF PROFIT AND COMPREHENSIVE INCOME FOR THE YEAR ENDED DECEMBER 31, 2010**

| | Previous | | IFRS Adjustments | | | |
|---|---|---|---|---|---|---|
| *(CA$ thousands)* | GAAP | Reclass | DO (2) | SBC (3) | E&E/PP&E (4) | IFRS |
| | | [Note 17 a] | [Note 17 d] | [Note 17 e] | [Note 17 b,c] | |
| Revenue | | | | | | |
| Oil and gas | 222,041 | | | | | 222,041 |
| Royalties | (25,592) | | | | | (25,592) |
| | 196,449 | – | – | – | – | 196,449 |
| Expenses | | | | | | |
| Production | 51,415 | | | | | 51,415 |
| Transportation | 2,809 | | | | | 2,809 |
| Interest and financing | 5,853 | | | | | 5,853 |
| General and administrative | 4,612 | | | | | 4,612 |
| Share based compensation | 3,262 | | | 1,404 | | 4,666 |
| Loss on disputed processing fees | 4,660 | | | | | 4,660 |
| Depletion, depreciation and amortization | 114,749 | (372) | | | 5,769 | 120,146 |
| Accretion on decommissioning obligations (1) | – | 372 | 381 | | | 753 |
| Asset expiries | – | | 976 | | 2,258 | 3,234 |
| | 187,360 | – | 1,357 | 1,404 | 8,027 | 198,148 |
| Gain (loss) on financial instruments (1) | – | 1,354 | | | | 1,354 |
| Realized gain (loss) on financial instruments | 3,693 | (3,693) | | | | - |
| Unrealized gain (loss) on financial instruments | (2,339) | 2,339 | | | | - |
| Gain (loss) on sale of capital assets | – | | | | 37,790 | 37,790 |
| Profit (loss) before taxes | 10,443 | - | (1,357) | (1,404) | 29,763 | 37,445 |
| Deferred income tax (recovery) | 3,860 | | (339) | | 7,759 | 11,280 |
| Profit (loss) and comprehensive income (loss) | 6,583 | - | (1,018) | (1,404) | 22,004 | 26,165 |
| Profit (loss) per share | | | | | | |
| Basic | 0.07 | | | | | 0.29 |
| Diluted | 0.07 | | | | | 0.29 |

(1) Caption has been renamed to comply with the financial statement presentation under IFRS.

(2) Decommissioning obligations has been abbreviated as "DO".

(3) Share based compensation has been abbreviated as "SBC".

(4) Exploration and evaluation assets has been abbreviated as "E&E" and property, plant and equipment has been abbreviated as "PP&E".

## RECONCILIATION OF STATEMENT OF CASH FLOWS

The transition from previous GAAP to IFRS has had no effect on the cash flows generated by the Company. The reconciling items between the previous GAAP presentation and the IFRS presentation have no net impact on the reported cash flows provided by or used in operating, financing and investing activities.

## EXPLANATORY NOTES

### a) Reclassifications

**Gain (loss) on financial instruments**

To conform to the statement of profit presentation under IFRS, the realized and unrealized gains (losses) on financial instruments are presented together on the statement of profit and detailed in the notes to the financial statements.

**Accretion on decommissioning obligations**

To conform to the statement of profit presentation under IFRS, the amount relating to accretion on decommissioning obligations has been presented separately; whereas, under previous GAAP, these amounts were included in depletion, depreciation and accretion.

**Deferred income taxes**

To conform to the statement of financial position presentation under IFRS, the current portion of future income tax assets and liabilities has been reclassified as long-term deferred income tax assets and liabilities.

### b) Exploration and evaluation assets

E&E assets consist of the Company's exploration projects which are pending the determination of reserves, and include undeveloped land. Upon determination of proved plus probable reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to PP&E.

At January 1, 2010 E&E assets were $39.0 million, representing the undeveloped land balance under previous GAAP. This resulted in a reclassification of $39.0 million from PP&E to E&E assets. At December 31, 2010, the Company's E&E assets were $67.8 million.

### c) Depletion, depreciation and amortization

Under IFRS, development and production assets are depleted at the reserve cost centre using the unit-of-production method based on the estimated proved reserves before royalties, whereas, under previous GAAP these assets were accumulated in country cost centres and depleted using the unit-of-production method based on the estimated proved reserves. As a result of depleting at the major area level, depletion, depreciation and amortization ("DD&A") increased $1.2 million and $5.8 for the three months and year ended March 31, 2010 and December 31, 2010, respectively, with a corresponding decrease to PP&E.

The Company chose to separate its cost centres using proved reserves. As a result, the company was required to test for impairment at the CGU level. The Company determined that one asset was impaired resulting in a charge against earnings in the amount of $2.4 million, before income taxes, as of January 1, 2010. At December 31, 2010, there were no indicators of impairment; therefore, an impairment test of PP&E was not required.

#### d) Decommissioning obligations

In accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets and IFRS 1, the Company revalued its decommissioning obligations, known as asset retirement obligations under previous GAAP, using a risk free discount rate at January 1, 2010 and recognized the difference directly in retained earnings. Under previous GAAP, the Company's asset retirement obligations were discounted using an average credit-adjusted risk free rate of 8.5%, whereas under IFRS, the Company discounted its decommissioning obligations using an average risk free rate of approximately 3.9%. As a result, on transition, the value of the Company's decommissioning liability increased by $14.6 million, deferred income tax liability decreased by $3.6 million and retained earnings decreased $10.9 million. In addition, as at December 31, 2010, the value of the Company's decommissioning obligations increased by $15.8 million, including the January 1, 2010 adjustment and the accretion adjustment discussed above.

Consistent with the change in discount rate applied above, accretion on decommissioning obligations is calculated based on the relevant risk free rate. The Company recorded an increase in accretion on decommissioning obligations of $0.1 million and $0.4 million for the three months and year ended March 31, 2010 and December 31, 2010, respectively.

#### e) Share based compensation

In accordance with IFRS 2 Share-based Payment, as at the Transition Date the Company revalued its contributed surplus arising from share based compensation to recognize the impact of estimating forfeitures and changing to graded vesting whereby each traunche is individually valued with greater costs recognized up front instead of equally over three years, as was the case under previous GAAP.

# CORPORATE INFORMATION

**BOARD OF DIRECTORS**

ROBERT J. DALES [2,3,4]
President, Valhalla Ventures Inc.

WILLIAM C. GUINAN [1,5]
Partner, Borden Ladner Gervais LLP

ELDON A. MCINTYRE [2,3,4]
President, Jarrod Oils Ltd.

NEIL G. SINCLAIR [2,4,5]
President, Sinson Investments Ltd.

DAVID J. WILSON [3,5]
President & Chief Executive Officer, Celtic Exploration Ltd.

**OFFICERS**

DAVID J. WILSON
President & Chief Executive Officer

SADIQ H. LALANI
Vice President, Finance & Chief Financial Officer

MICHAEL R. SHEA
Vice President, Land

ALAN G. FRANKS
Vice President, Operations

[1] Chairman of the Board
[2] Member of the Audit Committee
[3] Member of the Reserves Committee
[4] Member of the Compensation Committee
[5] Member of the Disclosure Committee

**HEAD OFFICE**

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Suite 1000, 400 Third Avenue S.W.
Calgary, Alberta T2P 4H2

**BANKERS**

NATIONAL BANK OF CANADA
Suite 2700, 530 Eighth Avenue S.W.
Calgary, Alberta T2P 3S8

**AUDITORS**

PRICEWATERHOUSECOOPERS LLP
Suite 3100, 111 Fifth Avenue S.W.
Calgary, Alberta T2P 5L3

**EVALUATION ENGINEERS**

SPROULE ASSOCIATES LIMITED
Suite 900, 140 Fourth Avenue S.W.
Calgary, Alberta T2P 3N3

**STOCK EXCHANGE LISTING**

TORONTO STOCK EXCHANGE
Trading symbol "CLT"

**CELTIC'S ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS**

Celtic's Annual Meeting of shareholders will be held on Thursday, April 21, 2011 at 3:00 p.m. in the Grand Lecture Room at The Metropolitan Centre 333 - 4 Ave. S.W. Calgary, Alberta.

**ABBREVIATIONS**

| | |
|---|---|
| bbls | barrels |
| mbbls | thousand barrels |
| bbls/d | barrels per day |
| BOE | barrels of oil equivalent |
| mBOE | thousand barrels of oil equivalent |
| BOE/d | barrels of oil equivalent per day |
| mcf | thousand cubic feet |
| mmcf | million cubic feet |
| bcf | billion cubic feet |
| mmcf/d | million cubic feet per day |
| mmbtu | million British Thermal Units |
| MD&A | Management's Discussion and Analysis |
| GJ | gigajoules |
| T | tonnes |
| MT | thousand tonnes |
| AECO-C | Alberta Energy Company "C" Meter Station of the Nova Pipeline System |
| API | American Petroleum Institute |
| ARTC | Alberta Royalty Tax Credit |
| CICA | Canadian Institute of Chartered Accountants |
| BIT | before income taxes |
| WTI | West Texas Intermediate |

**CONVERSION OF UNITS**

Imperial = Metric
1 acre = 0.4 hectares
2.5 acres = 1 hectare
1 bbl = 0.159 cubic metres
6.29 bbls = 1 cubic metre
1 foot = 0.3048 metres
3.281 feet = 1 metre
1 mcf = 28.2 cubic metres
0.035 mcf = 1 cubic metre
1 mile = 1.61 kilometres
0.62 miles = 1 kilometre
1 mmbtu = 1.054 GJ
0.949 mmbtu = 1 GJ

Natural gas is equated to oil on the basis of 6 mcf = 1 BOE.

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Celtic
EXPLORATION LTD.

CELTIC'S NEW ADDRESS EFFECTIVE MAY 1, 2011:

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WEST TOWER
321 SIXTH AVENUE
SOUTH WEST /
CALGARY, ALBERTA
T2P 3H3 /
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